Integrated Single Electricity Market

(I-SEM)

Capacity Remuneration Mechanism

Detailed Design

Second Consultation Paper

SEM-15-104

21 December 2015

EXECUTIVE SUMMARY

Ireland and Northern Ireland has until the end of 2017 to change its wholesale electricity markets to meet the requirements of the European 3rd package of energy legislation. This legislation places a number of requirements on the wholesale electricity markets of Member States with the aim of improving energy trade within the EU. The Regulatory Authorities (RAs) for Ireland and Northern Ireland have agreed the High Level Design[1] of the market required for the third package - and called that market the I-SEM (Integrated Single Electricity Market).

The proposed I-SEM closely models the "Target Model" that sits at the heart of the European 3rd package. Specifically, it includes the following energy markets:

- **Day Ahead:** The Day Ahead Market (DAM) will operate at 11:00 on the day ahead of the physical delivery of electricity. This will be a cleared market – where parties offer to buy and sell electrical energy for each hour of the following day, and all trades are priced at the price of the most expensive trade that is consistent with the received offers and bids.
- **Intra Day:** The Intra Day Market is bilaterally traded, and will operate from the closure of the DAM to a "Gate Closure", being some point close to the physical delivery of electrical energy.
- **Balancing:** The Balancing Market (BM) operates up to the physical delivery. This is the market where the TSOs adjust the output of generators (and demand of customers) as required to maintain the balance of generation and demand, and ensure the system operates in a stable and secure manner. These adjustments are made based on price data submitted by those Generators (or DSUs). Any electrical energy that is produced or consumed, and which has not been explicitly sold or bought through one of these markets is deemed to have been bought or sold through the BM.

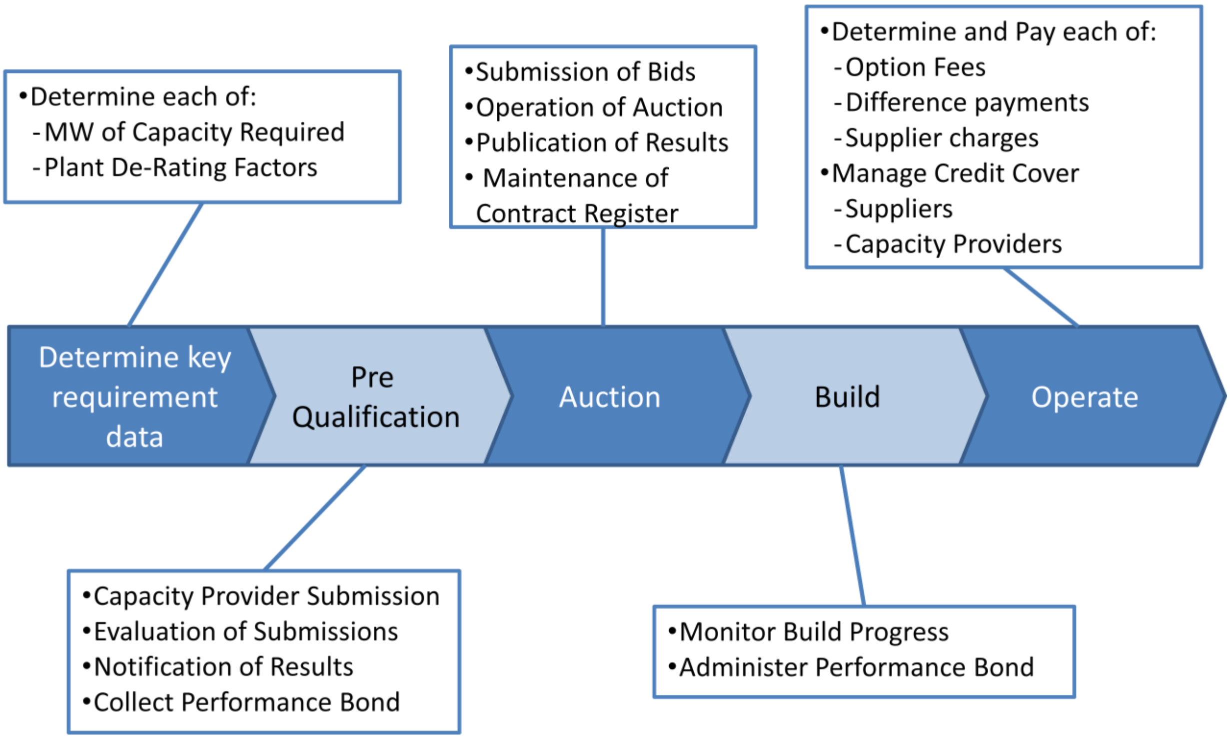
In addition to the above energy markets, the High Level Design includes a Capacity Remuneration Mechanism (CRM) based around Reliability Options. The CRM pays for the capacity to produce electrical energy on a "per MW" basis. This means that, typically, Capacity Providers can receive two payments

- A (per MW) capacity payment for being *available* to produce electrical energy; and
- An (per MWh) energy payment through one of the Day Ahead, Intraday or BM for any electrical energy they produce

The I-SEM CRM has 5 key stages as illustrated in Figure 1 below.

[1] http://www.semcommittee.eu/en/wholesale_overview.aspx?article=d3cf03a9-b4ab-44af-8cc0-ee1b4e251d0f

Figure 1: End to End Process for the I-SEM CRM



A number of decisions relating to the design of the I-SEM CRM have already been made. These decisions were consulted on in SEM 15-044, with the decisions set out in SEM 15-103. This paper is the second I-SEM CRM consultation and considers a number of areas that were not covered previously, or where more detail is required to progress the design of the CRM. This will be followed by a third I-SEM CRM consultation covering the detailed design of the Auction stage, measures to address market power, as well as design issues that remain outstanding following this (2^{nd}) I-SEM CRM consultation.

The areas covered in this consultation paper are:

- The arrangements for cross-border participation in the I-SEM CRM;
- The arrangements for secondary trading of Reliability Options;
- A number of details relating to the Reliability Options awarded to Capacity Providers. Specifically:
  - The duration (in years) of Reliability Options, and whether this should vary between new and existing plant;
  - Whether the Option Fee should be subject to indexation;
  - The appropriate level for any “stop loss” limits; and
  - The detailed design of the Implementation Agreement used during the build phase to incentivise the prompt delivery of new capacity.
- The €/MWh level of Administered Scarcity Price; and

- Transitional arrangements for the introduction of the I-SEM CRM.

Cross Border Participation

The SEM is currently connected to the GB electricity market through two electrical interconnectors, and it is possible that further interconnectors will be built in the future (linking the I-SEM to GB or elsewhere). In order to ensure that competition in the I-SEM CRM is maximised and consumers receive the benefits of interconnected capacity it is important that the CRM recognises, and provides incentives for, the contribution that interconnected capacity makes to the I-SEM security standard. This contribution could come from:

- The presence of the interconnector itself; and/or
- The presence of capacity (e.g. generation) located outside the I-SEM, which can use interconnection to support security of supply in the I-SEM.

In line with EU Internal Energy Market Regulations and EC State Aid Guidelines, it is also important that the CRM does not distort cross border flows of energy and the underlying market coupling and balancing arrangements that are being designed under the EU Target Model; nor should it distort long run investment signals in the location of generation, demand side response, storage or interconnection between Member States or bidding zones.

This paper looks at five broad options for how the contribution of cross border capacity can be recognised and incentivised through the I-SEM CRM:

- **Net off demand**: This approach would quantify the expected contribution (positive or negative) of cross-border transmission capacity to the need for capacity in the I-SEM, and uses this to adjust the capacity to be procured from within the I-SEM. This approach does recognise that capacity will be provided across the interconnector; however, it does not provide any capacity payments to reflect the support (if any) provided by cross-border capacity. It is assumed that all cross-border providers are compensated in their local energy markets only, where these local energy markets reflect the increased generation that will flow across the interconnector. This is the approach that was used to date in the GB CRM.
- **Interconnector Led:** Under this approach, the interconnector participates in the I-SEM Capacity Remuneration Mechanism (CRM). This is the approach that has been implemented for the second Auction that took place in December 2015[2]. There are two variants of this option, depending on how the performance of the external provider is assessed:
  - **Performance based:** Performance is assessed based on actual flows at the relevant interconnector(s);
  - **Availability Based:** Performance is assessed based on the interconnector's availability at the relevant time.

[2] While no new build interconnectors cleared in the 2015 Auction in GB, 1,861,760 of existing interconnection cleared .
See:
https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/2015%20T-4%20Capacity%20Market%20Provisional%20Results.pdf

- **FTR Led: Under this** approach, the participants in the I-SEM CRM auction are the parties that hold the rights to any financial benefit of trade arising from cross border flows at the Day Ahead stage – through FTRs.
- **Provider Led:** Under this approach, providers located outside the I-SEM are able to participate directly in the I-SEM CRM. Mechanisms are put in place to adjust for losses between the provider and the I-SEM, as well as to ensure I-SEM consumers do not pay for capacity if it does not deliver to the I-SEM when required. There are two variants of this option, depending on how the performance of the external provider is assessed:
  - **Performance Based:** Performance is assessed based on actual flows at the relevant interconnector(s) as well as at the relevant provider's meter; and
  - **Availability Based:** Performance is assessed based on the relevant provider's availability to perform at the relevant time (e.g. by having offers to generate in all relevant energy markets within its Member State).
- **Hybrid**: This approach is a hybrid of the "Provider Led" and "Interconnector Led" approaches. Providers located outside the I-SEM are able to participate directly in the I-SEM CRM; however:
  - The interconnectors will make any difference payments which arise as a result of a technical failure of their asset; and
  - The Interconnectors are able to retain any difference in the clearing (€/MWyear) prices for capacity in I-SEM and the relevant neighbouring market.

Secondary Trading

There will be times when a Capacity Provider is unable to provide the capacity it committed to in entering into a Reliability Option (it is unavailable). Under normal circumstances, this would leave that Capacity Provider exposed to the potential it will, on net, make payments[3] under its Reliability Option. Efficiency is enhanced if the relevant Capacity Provider is able to enter into a secondary trade that transfers its Reliability Option rights and obligations for the period it is unavailable.

We consider a number of elements relating to the design of secondary trading arrangements, notably:

- **Direct 'v' Financial:** Under the direct approach, the central register of reliability options is updated to show the transfer of all or part of a Reliability Option to a third party. Under the financial approach, the central register is unchanged, but the party voluntarily transfers all or part of its Reliability Option payments to a third party. It would be difficult to preclude financial trading; however direct trading does offer some distinct benefits:

  With direct trades, for the quantity for Reliability Option traded, the original Reliability Option holder no longer receives option fees or has to make difference payments. These

[3] If market price went above the Reliability Option strike price, the provider would make difference payments but not have any revenue to offset those payments

payments now come directly from the party who has accepted that part of the Reliability option through secondary trading. The key benefit of this approach over financial trading is that the ultimate exposure to difference payments is more manageable by the party that now holds the Reliability Option. These difference payments will depend on where that party chooses to sell its output, rather than on the trading behaviour of the original Capacity Provider.

- **Capped at de-rated or name-plate capacity**: A Capacity Provider's allocation of Reliability Options[4] will be capped at that provider's de-rated capacity. There are arguments that, close to real time, Capacity Providers should be able to back an increased level of Reliability Options – up to a level between the de-rated and nameplate capacity of that provider. This recognises that:
  - There is increased certainty over the reliability and output of plant at times close to delivery;
  - This margin of capacity is implicitly required to cover planned maintenance outages in a system where there is "just enough" capacity.
- **Timescales and Products:** The efficiency of secondary trading is enhanced if it allows trades that match the genuine needs of participants, as well as providing some transparency on price. This argues for:
  - Secondary trading before plant has been commissioned. This provides developers with a route to exit projects in a way that manages or mitigates the impact of that exit on Security of Supply;
  - Secondary trading at all points up to the fixing of data for market settlement. This would include a limited window for "ex-post" trading;
  - Ensuring the products traded should not be overly standardised – as they should allow for trading to cover a day (e.g. to cover a forced outage) through to weeks (e.g. to cover a maintenance outage) and years (e.g. to cover a catastrophic plant failure)
  - The derivation and publication of anonymised pricing information relating to secondary trades.

Detailed Reliability Option Design

This paper considers a number of details relating to the Reliability Options awarded to Capacity Providers. Specifically:

- **Duration:** While our assumption is that existing capacity providers that clear in the CRM Auctions will be awarded annual contracts, there are benefits in awarding longer-term Reliability Options to plant requiring investment. This will lower costs to consumers by reducing the financing costs of new plant, and allowing them to compete effectively with established plant. This paper explores a number of options for the actual length of Reliability

[4] Through the auctions

Option awarded to new plant, and for how we identify plant as new or existing. The options considered for Reliability Option length are:

– **Generic economic life (e.g. 15 years)**. This is similar to the approach used in GB. Whilst this leads to low financing costs, it does contain the risk that some plant will benefit from Reliability Option Fees beyond the date at which that plant should have closed.
– **Balanced Economic Life (e.g. 10 years)**. This fixes Option Fees for a shorter period. Plant with an economic life that is longer than this period will be able to obtain Option Fees for the remainder of their economic life by competing (as existing plant) in auctions for annual Reliability Options after the expiry of their initial (and long) Reliability Option. The time value of money reduces the impact of these later (annual) revenues on the financing of the plant
– **Shortest Economic Life (e.g. 5 years)**. This fixes Option Fees for a period that is towards the low end of Capacity Providers' economic lives. This approach would significantly reduce the risk of stranded costs to consumers (from capacity remaining on the system beyond the end of its economic life), but is also likely to increase the cost of some or all new entrants to the point where they cannot displace existing participants that may, themselves, be beyond their economic lives – so increasing stranded costs. On balance, this is likely to increase the level of stranded costs paid by consumers.
– **Technology Specific Economic Life**: It may be possible to define different Reliability Option lengths to match the economic lives of different technologies. Whilst this is theoretically possible, it is likely to be difficult to do in practice in a way that covers all (including emerging) technologies. In fact it is likely that the estimates of economic life would be subject to a significant error margin.

The options presented for identifying "new" as opposed to "existing" plant are:

– **Cost Threshold:** Any project with a spend per MW above a pre-specified threshold is considered to be new-build, with a similar (but lower) threshold for refurbished plant;
– **Tangible Facts:** The decision over whether a specific capacity provider is classified as a new-build, upgrade or existing plant is based on observable facts relating to that provider as clearly and transparently established by the RAs; and
– **Expert Judgement:** The "expert judgement" approach adds to the "tangible facts" approach to provide a judgement on whether capacity is actually new, existing or an upgrade. It is expected that such expert judgement would be provided to the RAs through a transparent process. In addition to the tangible facts, this would include a review of the actual investment in the plant providing the capacity

- **Fee Indexation:** Each auction will determine the (€/MWyear) Option Fee that is applied to Reliability Options that are allocated through that auction. The efficiency of the CRM is enhanced if this Option Fee increases in line with legitimate increases in costs of Capacity Providers. This is most significant for "new" plant that will face more significant fixed costs, and will hold longer-term Reliability Options. The bulk of new plant fixed costs relate to the financing of the initial investment – which may (if they use index liked debt) rise in line with inflation.

- **Stop Loss:** There will be limits on the extent to which Capacity Providers can make a net loss on their Reliability Options. We consider:
  - Whether these limits should apply on an annual, monthly or daily basis (or some combination of the three); and
  - The actual level of the limits that should apply.
- **Implementation Agreements:** Implementation Agreements will cover the build phase – and seek to ensure that developers are appropriately incentivised to:
  - Deliver capacity as contracted; or
  - Abandon clearly failing projects early – allowing alternative capacity to be procured to minimise any capacity shortfall (and consequent impact on Security of Supply)

  The Implementation Agreement works by measuring project progress against a number of milestones. The Reliability Option would be terminated if significant milestones are missed – leading to a need for the developer to pay a termination fee. The developer is required to provide an up-front performance bond to cover that termination fee. This paper looks at a number of detailed issues relating to the design of the implementation agreement including:

  - **Definition of milestones:** Recent experience in GB has highlighted the consequence for security of supply of new capacity being delivered late or not at all. With this in mind, it is important to have milestones and incentives that support the early identification of failing projects. We have reviewed milestones used in other CRMs, as well as those typically used for the construction of power stations. On this basis, we have proposed a number of generic milestones to be applied to all new capacity (recognising that some of these may need to be selectively ignored if they are not relevant to the technology)
  - **How long should be allowed for construction?** We suggest a period of 4 years, based on international experience; however, we note that DS3 is considering allowing a period of up to 5 years
  - **How long should be allowed for commissioning?** Following the construction window, plant will be allowed an additional time window to prove it can deliver its capacity. During this window, the relevant provider will only receive Reliability Option Fees for the capacity it has proved. This window is 12 months in GB, we note that this period is broadly consistent with the level of penalties that are typically applied in EPC[5] contracts associated with the construction of new power stations
  - **Size of penalties:** We consider the size of termination fee that should be applied to projects that fail to meet a significant milestone. We note that there is a trade off between high termination fees that reflect the consequential costs to the system, and lower fees that may reduce barriers to entry for new participants.
  - **Progress Reporting:** We consider whether 6 monthly reporting of progress by developers to a central body represents an appropriate balance between the costs of

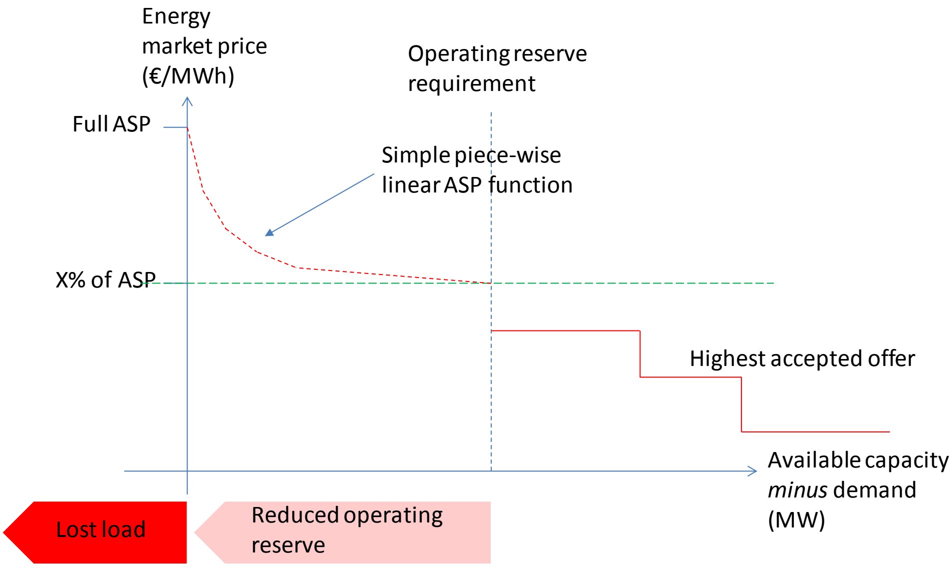
[5] Engineering, Procurement Construction and Commissioning

that reporting, and the need to identify failing projects that may impact security of supply.

Administered Scarcity Price

It has been decided that the I-SEM Balancing Market will include an Administered Scarcity Price. This will act as a floor on Balancing Market prices when capacity is less than the aggregate of the demand for electricity, and the need for reserve. The Administered Scarcity Price will be described as a five-part piecewise linear function as shown in Figure 2.

Figure 2: Piecewise linear Administered Scarcity Price function



This consultation looks at the detailed specification of the Administered Scarcity Price, specifically considering:

- The definition of load shedding (at which point the Full Administered Scarcity Price would apply);
- The level of the Full Administered Scarcity Price (FASP);
- Whether FASP should start low for an initial period; and
- The definition of the Operating Reserve Requirement. This looks at the current levels of reserve held by the TSOs.

For the definition of load shedding we have reviewed the definition of Eirgrid "Red Alerts" as well as precedents from GB. These lead to load shedding being based on one or more of the following:

- A significant drop in voltage;
- A significant drop in system frequency; and/or
- Other involuntary reduction of customer load.

For the enduring level of FASP, we have considered four options as set out below. Of these, there is a clearer rationale for the first two options, with the last (PCAP) option having the least justification:

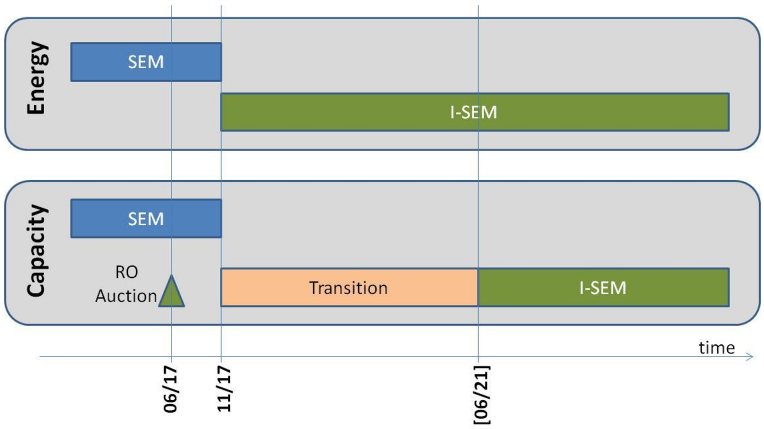
- **VoLL:** FASP is set to the current estimate of the Value of Lost Load for the I-SEM system. For 2016 this is €11,017.98. Under the current SEM, this value will increase on an annual basis in line with inflation.
- **EU Consistent:** FASP is set consistent with its equivalent value in neighbouring electricity markets. This currently is the GB market, implying a value of €4170/MWyear rising to €8340/MWyear from late 2018[6];
- **Euphemia Cap:** FASP is set at the Euphemia cap for the day-ahead market. This is currently €3,000/MWh
- **PCAP:** FASP is set at the current (€1,000/MWh) Pool Price Cap in the SEM

There are arguments for setting FASP at I-SEM go-live to be below that implied from the above options. This will allow any change to market prices to be introduced progressively, increasing the overall stability of the market. We look at the length of time for the transition to the enduring FASP (GB has adopted around 3 years) as well as whether FASP should increase progressively over this period.

Transition

As illustrated in Figure 3, the anticipated lead time[7] between the first main auction for the allocation of Reliability Options and the start of those options leads to transitional period. Neither the existing SEM CRM, nor the Reliability Options from that first auction, will be paying for Capacity that operates during this transitional period. We have to decide which providers are paid for capacity, and the rate at which they are paid.

Figure 3: Movement from SEM CRM to I-SEM CRM.



We have considered three options for the treatment of this transitional period:

- **Auction each year separately**: Under this option each round of capacity auctions would procure the balance of capacity required for the Capacity Year immediately following those auctions, as well as the bulk of the capacity required for Capacity Year + n[8]. For the first "n"

[6] Values are £3,000 and £6000 respectively, converted to Euro at an exchange rate of £1.39/€
[7] This lead time is illustrated as
[8] "n" is the length of time (in years) allowed for plant construction

years, the year-ahead auctions will be procuring all of the capacity required for that capacity year;

- **Auction as a block:** Under this option the first (June 2017) round of capacity auctions would procure the bulk of the required capacity required for each of the transition years, as well as for the following Capacity Year (year + n). Each subsequent annual round of auctions would procure the bulk of the required capacity for "year + n", as well as a small amount of capacity to fine-tune the level of contracted capacity for the Capacity Year immediately following those auctions.
- **Do Nothing:** Under this option, Capacity Providers receive no Capacity Payments during the transition period. This may be combined with a low level of Administered Scarcity Price for the transitional period in order to manage risks to suppliers and consumers from extreme price spikes without the concomitant protection that the hedging mechanisms of the Reliability Option provides.

Next Steps:

Interested parties are invited to respond to the consultation, presenting views on the options, proposals and discussion in this paper.

Responses to the consultation paper should be sent to Natalie Dowey (natalie.dowey@uregni.gov.uk) and Thomas Quinn (tquinn@cer.ie) by 17:00 on Friday 5th February.

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 PHASE OF THE I-SEM CAPACITY MECHANISM

1.1.1 Over the course of 2014 the SEM Committee consulted extensively before publishing the decision paper on the High Level Design (HLD) for the I-SEM in keeping with our statutory objectives. The HLD decision sought to maximise benefits for consumers in the short-term and long-term, while ensuring security of supply and meeting environmental requirements. Following the HLD, the Detailed Design Phase of the I-SEM commenced and a number of workstreams were established including the CRM workstream.

1.1.2 The purpose of the CRM Detailed Design is to develop through consultation the specific design features of the new capacity mechanism that are consistent with the High Level Design of the I-SEM. Following on from this, detailed legal drafting of the CRM market rules will be completed. These detailed legal rules in the current SEM take the form of the Trading and Settlement Code.

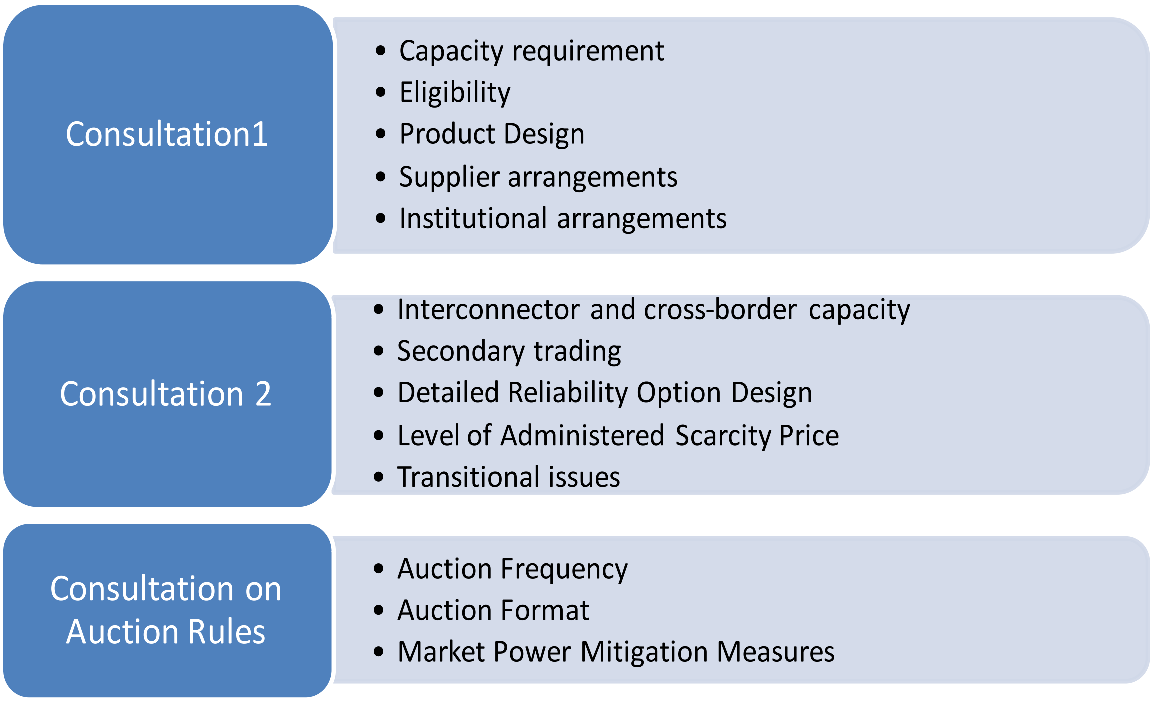
1.1.3 The SEM Committee and the Regulatory Authorities (RAs), in close cooperation with the Departments will continue to engage with the EC on the design of the I-SEM Capacity Mechanism, to ensure that the detailed design complies with existing and emerging European rules and guidelines.

1.1.4 In addition to the detailed policy design the RAs will be working with the TSOs in relation to systemisation and codification of the mechanism. It is important to ensure that there is alignment between CRM development, other I-SEM workstreams and DS3 System Services.

1.2 CONTEXT

1.2.1 This paper is the second in our three stage consultation process for the development of the CRM Detailed Design. This three stage consultation process is illustrated in Figure 4 below

Figure 4: Three stage consultation process.



1.2.2 The key issues discussed in this second consultation paper are:

- Interconnector and cross-border capacity

  This section considers a number of options to regonise the contribution of non-I-SRM providers, specifically

  - Net off demand
  - Interconnector led
  - FTR led
  - Provider led (Performance or Availability based)
  - Hybrid of Provider and Interconnector

- Secondary trading

  This section considers,

  - The case for secondary trading
  - The secondary trading market place
  - Qualification
  - Stop Loss limits and secondary trading

- Detailed Reliability Option Design

  More detailed issues relating to the design of the contractual arrangements for consideration including:

  - Reliability Option contract length

- implementation agreement

- Level of Administered Scarcity Price

  Building on decision paper 1 and considers the following:

  - definition of load shedding
  - level of full administrative scarcity price
  - definition of target operating reserve and setting of the ASP function

- Transitional issues

  This section considers a number of transitional issues for the introduction of the I-SEM Capacity Remuneration Mechanism. These issues fall into the following two areas:

  - The transition from the SEM Capacity Mechanism to the I-SEM Capacity Remuneration Mechanism; and
  - Whether elements of the I-SEM CRM (e.g. the level of any Administered Scarcity Price) should be phased in over time.

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

  - 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.
  - The RAs also hosted a stakeholder workshop on the CRM on 8 May 2015 to discuss the first consultation paper prior to publication of the same.

- Following the publication of the first consultation paper a further stakeholder workshop was held on 31st July.
- In September the RA's held two stakeholder workshops on 28th and 29th September to cover the first consultation emerging thinking and the second consultation respectively.

A further stakeholder forum on this second consultation will take place early 2016. An invite will be issued for all interested parties on the AIP website in due course.

TSO engagement on implementation

1.3.3 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)

1.3.4 We have engaged 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.

Department of Energy and Climate Change (DECC) and Ofgem

1.3.5 The RAs have been and will continue to liaise with DECC and Ofgem on cross border issues in particular. Discussions with DECCs on their recent experience of implementation of the CRM in Great Britain have been helpful in this process. We will be engaging with National Grid (NG) on cross border participation in the CRM as part of this consultation.

Department of Enterprise Trade and Investment (DETI) and Department of Communications, Energy and Natural Resources (DCENR)

1.3.6 Throughout the development of the first and second consultations we continued to work closely with DETI and DCENR on all of the policy issues and the State Aid process.

1.4 CRITERIA FOR ASSESSING

1.4.1 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.

1.4.2 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.

1.4.3 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.

1.4.4 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.

2. INTERCONNECTOR AND CROSS-BORDER CAPACITY

2.1 INTRODUCTION

2.1.1 Under the EU Electricity Target Model cross zonal flows are determined by market coupling at the day ahead, intra- day and ultimately through TSO-TSO arrangements at the balancing timeframe which should ensure that power flows to where it is most valued at a given moment in time.

2.1.2 Within this context, several EU Member States have implemented or are in the process of implementing CRMs and consideration is being given at European and national level as to how to ensure that these do not distort the EU Internal market[9]. In practice, this means that nationally focussed CRMs should be open to participation from cross border capacity such that competition in CRMs is maximised and long run efficient investment incentives are sent to signal where capacity is located and investment signals are provided to interconnection where transmission capacity is constrained.

2.1.3 Capacity located outside the I-SEM will be able to contribute to satisfying the I-SEM Security Standard and it is important that long run investment signals are not distorted in favour of all-island capacity providers and against investment in cross border capacity (both foreign capacity providers and interconnectors). The relevant capacity will be capable to impacting the flow of electricity over an interconnector linking the I-SEM to an adjacent market. It is important to emphasise that we expect market coupling and cross border balancing arrangement between GB and I-SEM to be the main vehicle for determining cross border flows and for dealing with coincident or non coincident scarcity. Notwithstanding this, it is important that the benefits of the reliability option in terms of de-risking long term investment are made available to cross border capacity both to ensure that the internal market is not distorted and to ensure that all-island consumers pay the lowest cost for security of supply.

At this time there are two such interconnectors:

- **EWIC:** a 500MW High Voltage Direct Current (HVDC) link between the Ireland (North of Dublin) and GB (North Wales); and
- **Moyle**: a 500MW High Voltage Direct Current (HVDC) link between Northern Ireland and GB (Scotland).

[9] See: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/358141/Frontier_economics_Report_Participation_of_Interconnected_Capacity_in_the_GB_Capacity_Market__Fro___.pdf and

http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_6_draft.pdf

2.1.4 The contribution of (existing and potential) non-I-SEM capacity providers in meeting the I-SEM capacity requirement clearly has potential benefits to I-SEM consumers. Allowing non-I-SEM providers to compete on an equitable basis should ideally:

- Provide the potential to lower costs to consumers for an equivalent security of supply;
- Support efficient usage of existing resources (generation, demand side and storage capacity providers and transmission capacity) within the I-SEM and its neighbouring markets;
- Provide appropriate incentives for investment in new interconnectors and generators (as well as demand side response and storage) between the I-SEM and other electricity markets.

2.1.5 The above benefits are recognised by the European Commission in a number of areas. For example, the State Aid guidelines state that measures should be designed to allow:

> *"the participation of operators from other Member States where such participation is physically possible in particular in the regional context, that is to say, where capacity can be physically provided to the Member State implementing the measure and the obligations set out in the measure can be enforced"*[10].

Availability or Performance Based Obligation

2.1.6 The treatment of cross border participants in the options described below will depend on whether the option is based on a performance or an availability model.

- In a performance based model the participant's obligation is not based on their availability to perform but on the actual flows at the relevant interconnector(s).
- In an availability model the participant is liable if it fails to meet its obligation, based on being available to perform.

2.1.7 Within the I-SEM, participants performance will be measured against a performance based model. For equity reasons we would favour if non I-SEM participants performance was also measured based on a performance based model but given some of the complexities described in this section, hence we are also consulting on availability based approaches.

2.1.8 We have considered five approaches to recognise the contribution of non-I-SEM providers, specifically:

- **Net off demand**: This approach would quantify the expected contribution (positive or negative) of cross-border transmission capacity to the need for

[10] 232(b), Guidelines on State aid for environmental protection and energy 2014-2020. 2014/C 200/1

generation capacity in the I-SEM, and uses this to adjust the generation capacity to be procured from within the I-SEM. This approach does recognise that generation capacity will be provided across the interconnector; however, it does not provide any explicit capacity payments to particular resources to reflect the support (if any) provided by cross-border capacity. This approach has been used in the GB CRM.

  - **Interconnector led:** Under this approach, the interconnector participates in the I-SEM Capacity Remuneration Mechanism (CRM). There are two variants of this option, depending on how the performance of the external provider is assessed:
    - **Performance based:** Performance is assessed based on actual flows at the relevant interconnector(s);
    - **Availability based:** Performance is assessed based on the relevant interconnector's availability to perform.

- **FTR led:** Under this approach, the participants in the I-SEM are the parties that hold the rights to any financial benefit of trade arising from the cross border flows at the Day Ahead stage – through FTRs.
- **Provider led:** Under this approach, providers located outside the I-SEM are able to participate directly in the I-SEM CRM. Mechanisms are put in place to adjust for losses between the provider and the I-SEM, as well as to ensure I-SEM consumers do not pay for capacity if it does not deliver to the I-SEM when required. Again there are two variants of this option:
  - **Performance based:** Performance is assessed based on actual flows at the relevant interconnector(s) as well as at the relevant provider's meter; and
  - **Availability Based:** Performance is assessed based on the relevant provider's availability to perform at the relevant time (e.g. by having offers to generate in all relevant energy markets within its Member State).
- **Hybrid**: This approach is a hybrid of the "Provider Led" and "Interconnector Led" approaches. Providers located outside the I-SEM are able to participate directly in the I-SEM CRM; however:
  - The interconnectors will make any difference payments which arise as a result of a technical failure of their asset; and
  - The Interconnectors are able to retain any difference in the clearing (€/MWyear) prices for capacity in I-SEM and the relevant neighbouring market.

2.1.9 Ideally, each of these approaches will be implemented in a way that allows capacity providers that are located outside the I-SEM to be treated in a way that is equivalent to that for those located inside the I-SEM. However there are significant differences in how each of these approaches are implemented and potentially the effect that they have on investment signals, security of supply and competition. In order to ensure that non I-SEM capacity would be treated on an equitable basis with I-SEM Capacity this would mean that:

- **De-Rated:** They are able to compete to be allocated Reliability Options up to their "de-rated" capacity – where the de-rating factor reflects a plant's marginal contribution to the I-SEM security standard. De rating reduces the plant's "name plate" capacity to reflect how it reduces the overall need for "name-plate" capacity from other providers to satisfy the security standard.
- **Measure Delivery in each relevant I-SEM or non I-SEM energy market**: Capacity providers located in the I-SEM will make difference payments if the I-SEM market price at which they sell their physical electricity is higher than the Reliability Option strike price. For non I-SEM providers to make equivalent difference payments it is necessary to measure:
    - The quantity they sold in each of the Day Ahead, Intraday and Balancing markets; and
    - The price that applied for each of those sales.

2.1.10 The following sections first discuss the issues associated with de-rating and measuring interconnectors before discussing each of the five approaches to recognising the contribution of interconnectors.

2.2 INTERCONNECTOR DE-RATING

2.2.1 As with other capacity providers, the Interconnector will need to be de-rated to reflect the extent to which it is expected to contribute to the I-SEM capacity requirement. This de-rating will be required irrespective of the approach adopted for the treatment of interconnectors and cross-border participation in the I-SEM Capacity Remuneration Mechanism

2.2.2 How the de-rating factor is determined is more complicated for interconnectors than other forms of capacity - reflecting expected physical availability and also the direction of flows across the interconnector during stress events. Flows across interconnectors are, in the first order, driven by market coupling and cross border balancing arrangements which reflect differences in the market price of energy at each end of those interconnectors.

2.2.3 As with other capacity providers, these factors can be considered on an ex-post or ex-ante basis:

- **Ex-post:** This approach considers the historic flows into the I-SEM at times when difference payments (and system stress events) are likely to be required under Reliability Options. At least initially, historic interconnector flows may not be a good indicator of those in the future. Interconnector flows are driven by energy prices in GB and the I-SEM.

Both of these will change as a result of changes to the respective energy markets. The impact of these changes will become clear over time; however initially an assessment would be required to determine the extent to which the changes were likely to impact interconnector flows. Notable changes include:

- **Bidding Code of Practice (BCoP):** The SEM incorporates a Bidding Code of Practice that requires generation participants to submit offers into the pool at short run marginal cost, which would have prevented SEM prices rising at times of scarcity. It is yet to be decided whether the I-SEM will incorporate some form of bidding controls that would limit the ability of any market participant to bid above marginal cost;; however, the adoption of administered scarcity pricing will mean that I-SEM prices are able to rise to higher levels than those in the SEM under similar conditions;
- **SEM Capacity Payments:** Imports to the I-SEM were able to earn capacity payments for sales of energy into the SEM. This increased payment may suggest that historic (SEM) flows on the interconnector over-estimate future (non-SEM) contribution at times of system stress. However, the SEM Capacity Payments mechanism acts in conjunction with the requirement to bid SRMC and therefore these factors may cancel each other out; and
- **GB Carbon Price Floor:** GB has adopted a carbon price floor which varies over time. The traded price of Carbon is an element of the fuel cost for thermal generators. When the European traded price is below the GB price floor, GB thermal generators will face a higher carbon component for their fuel costs than equivalents in the I-SEM. This increased Carbon cost could increase GB energy prices leading to a reduction in net flows from GB to SEM.

- **Ex-ante:** This approach carries out fundamental modelling of the European Power System under a number of scenarios. This results in a range of potential imports to the I-SEM at times of high prices.

2.2.4 Both of the above approaches have been considered for the treatment of interconnectors in the GB CRM, with analysis indicating a wide range of potential values for the relevant de-rating factors[11].

2.3 QUANTIFYING CROSS BORDER FLOWS

2.3.1 I-SEM Reliability Options lead to an obligation for capacity providers to make difference payments when the I-SEM energy market price is above the Reliability Option strike price. For capacity providers located in the I-SEM, this means difference payments under their Reliability Options will be determined as follows. :

[11] “Announcement of de-rating methodology for interconnectors in the Capacity Market”, DECC February 2015

- *Day Ahead:* For power sold in the I-SEM DAM (up to the quantity contracted through a Reliability Option), difference payments will be paid based on the difference between the Day Ahead Price and the Strike Price.
- *Intra Day:* For power sold in an I-SEM Intra Day Market (up to the remaining quantity contracted through a Reliability Option), difference payments will be paid based on the difference between the traded price and the Strike Price.
- *Balancing:* For power sold through the BM (up to the remaining quantity contracted through a Reliability Option), difference payments will be paid based on the difference between the relevant BM Price and the Strike Price.
- *System Services:* For any power utilised for Ancillary or System Services, difference payments will be paid based on the difference between the contracted utilisation payment for that service[12] and the Strike Price.
- *Delivery Shortfall or Surplus:* For any capacity contracted through a Reliability Option that hasn't been utilised for System (Ancillary) Services, or otherwise sold through an I-SEM market, difference payments will be paid based on the difference between the BM Price and the Strike Price.

2.3.2 Applying this Reliability Option settlement for cross border capacity means that, irrespective of the overall approach to cross border capacity, we need to measure:

- The quantity cross border participants sold in each of the Day Ahead, Intraday and Balancing markets; and
- The price that applied for each of those sales.

2.3.3 Each of the above can be identified both at the aggregate level (covering the entirety of an interconnection between the I-SEM and an adjacent market), as well as at the level of specific participants.

2.3.4 The following paragraphs consider:

- The top down identification of the cross border flows arising from the day-ahead, intra-day and balancing markets. This will give the total flow between the I-SEM and an adjacent market; and
- How these top down flows can be allocated between non-I-SEM participants as required for each approach.

Day ahead aggregate cross border flows

2.3.5 Within the EU Target Model, Day Ahead Market coupling will result in an implicit flow across each interconnector within a market coupling zone. This implicit flow can be quantified relatively simply for the I-SEM interconnectors. This quantification is based on the difference between the quantity of power bought and sold by participants in the I-SEM power exchange, specifically:

[12] Likely to be zero – implying no difference payments in respect of the provision of Ancillary or System Services.

DAQ = DA_I-SEM_Purchases - DA_I-SEM_Sales

Where: DAQ is the MWh quantity of power imported to the I-SEM at the day-ahead stage.

DA_I-SEM_Purchases is the MWh quantity of power purchased by those that participate directly in the I-SEM day ahead market; and

DA_I-SEM_Sales is the MWh quantity of power sold by those that participate directly in the I-SEM day ahead market.

2.3.6 As provided for under the CACM Regulation, the settlement of the I-SEM day-ahead market will need to explicitly quantify this day-ahead flow to ensure payments are made to and by the relevant interconnector.

Intraday aggregate cross border flows

2.3.7 The Intraday market will be a continually traded market – with each trade having a different price. In effect, the operators of the I-SEM intra-day market will facilitate trades between buyers and sellers of power for delivery in the I-SEM. In practice, the market operator is typically inserted as an intermediary for all trades – meaning that:

- Where buyer "A" accepts an offer to sell from party "B", this results in "B" selling to the market operator, and the market operator then selling on to "A"; and
- Traders do not know the identity of the ultimate counterparty – as their counterparty (and hence credit risk) is the market operator.

2.3.8 An intra-day trade will impact the (implicitly) contracted interconnector flows if one of the buyer or seller ("A" or "B" in the above bullet points) is located outside the I-SEM. Whether a participant is or isn't an I-SEM participant dependss on *where* they entered their bid or offer:

- **I-SEM Intra Day Market**: If the bid or offer was entered on an I-SEM intra-day market, that bid or offer is considered to be for delivery in the I-SEM price zone.
- **Other Intra Day Market**[13]: If the bid or offer was entered on an intra-day market for one of the other price zones in Europe,
    - delivery of I-SEM power to satisfy such a bid would require an export of power from the I-SEM; and
    - an import of power to the I-SEM would be required to honour such an offer.

2.3.9 Again, as set out in the CACM Regulation and as being developed as part of the ETA arrangements for I-SEM, the central settlement of the energy market will need an

[13] Market coupling should identify those bids and offers on the intra-day market for any given price zone that can be delivered in another price zone, and enter those (suitably adjusted) bids and offers on the intra-day market for that other price zone.

identification of these trades to determine the impact on contracted flows across interconnectors.

Traded Balancing Market aggregate cross-border flows

2.3.10 The I-SEM TSOs will use the balancing market to maintain the balance between the production and consumption of electricity, as well as to address operational constraints on the system (e.g. to ensure there is sufficient reserve, or arising from transmission constraints). As with the Intra-day market, the TSOs will see offers and bids from I-SEM participants, as well as bids and offers made in other markets that can influence the flow on the interconnector.

2.3.11 The settlement of Reliability Options will require the identification of those trades entered into by the I-SEM TSOs with parties from outside the I-SEM.

Balancing market delivery shortfall or surplus aggregate cross-border flows

2.3.12 Once energy has been delivered, the interconnector meters will show how much power actually flowed across that interconnector. This will need to be compared with the contracted flows from each of the preceding market timescales (day ahead, intra-day and instructed imbalances) to derive the net imbalance between the dispatch and metered quantities for all flows between the I-SEM and GB markets.

2.4 APPROACHES TO THE TREATMENT OF CROSS BORDER CAPACITY

2.4.1 The following paragraphs consider five approaches for how to recognise the contribution of non-I-SEM capacity in meeting the I-SEM security standard. In each case, this looks at how the aggregate cross border flows (see section 2.3 above) are allocated between the resulting non-I-SEM participants. The approaches considered are:

- Net off demand;
- Interconnector led;
- FTR led;
- Provider led; and
- Hybrid (provider and interconnector).

Net off demand

2.4.2 This approach is based on an estimation of the contribution that interconnectors will make to the need for I-SEM capacity. This estimate is then used to adjust the quantity of capacity that is procured from providers located in the I-SEM. This is the approach that was used for the first Auction (December 2014) of the GB Capacity Remuneration Mechanism and is currently applied in the new capacity obligation mechanism in France.

2.4.3 In this assessment the contribution of interconnectors could be either positive or negative, e.g:

- **Positive:** The interconnector typically flows power out of the I-SEM, increasing the demand to be met by I-SEM capacity and hence quantity of I-SEM capacity required; or
- **Negative:** The interconnector typically flows power into the I-SEM, reducing the demand to be met by I-SEM capacity and hence the quantity of I-SEM capacity required.

2.4.4 Whilst this approach has the attraction of being simple, it also had a number of issues, notably:

- **Implicit recognition of cross border capacity:** Whilst this approach does account for the contribution of cross border capacity, that capacity clears through the energy markets and does not receive a payment through the Capacity Remuneration Mechanism. This means:
    - Where the interconnector is judged to increase the need for I-SEM capacity, the total cost of that capacity will increase relative to not accounting for cross border capacity in the CRM at all. This increase is driven both by an increase in the quantity of capacity procured, and the potential increase in the price (€/MWyear) paid for that capacity. I-SEM consumers will pay that increased capacity cost in full, even though the need for that capacity is driven by consumers outside of the I-SEM; and
    - Where the interconnector is judged to reduce the need for I-SEM capacity, the total cost of that capacity will reduce relative to not accounting for cross border capacity in the CRM at all. This reduction is driven by a reduction in the quantity of capacity procured. I-SEM consumers benefit from this reduced cost – making no capacity payment for capacity provided via the interconnectors

- **Impacts up-stream investment:** It is desirable that the I-SEM CRM should incentivise appropriate decisions to build new plant, or investment in demand side response and storage, as well as to close existing plant. Under this option:
    - I-SEM CRM incentives are constrained to providers located in the I-SEM price zone, rather than considering whether it is more appropriate to build new, or close old, plant in neighbouring markets;
    - I-SEM Energy incentives (i.e. the prospect of earning energy prices above the I-SEM CRM strike price) will apply to capacity providers located outside the I-SEM in a similar manner to capacity located within the I-SEM that does not

hold a Reliability Option[14]. The future revenue for such plant would be less certain than if it had a Reliability Option; however, there is still an incentive to build or close.

- This issue can (at least partially) be offset if the Capacity Remuneration Mechanisms for other Member States anticipate the need for capacity to increase exports to the I-SEM.

- **Impacts "Hole in Hedge"**: Under this option, the quantity of capacity contracted through the I-SEM is different from that required to meet the demand of I-SEM consumers:
  - **Allocate less:** If the interconnectors are judged to reduce the need for I-SEM located capacity, the I-SEM will allocate less Reliability Options than are required to meet I-SEM consumption. This will contribute to any "hole in the hedge", meaning that Suppliers are only partially covered against the high energy prices that would arise when capacity is scarce; or
  - **Allocate more:** If the interconnectors are judged to increase the need for I-SEM located capacity, the I-SEM will allocate more Reliability Options than is needed to meet I-SEM consumption. If energy prices rose above the Reliability Option strike price, there would then be a surplus of Reliability Option difference payments. This surplus would offset any actual "hole in the hedge".

Interconnector Led Approach

2.4.5 Under this approach, the non-I-SEM participants in the I-SEM CRM would be the owners of the relevant interconnectors, who would bid into the auction and, if successful, receive the I-SEM CRM clearing price. The interconnectors would retain any capacity revenues providing they fulfil the conditions of the obligation placed upon them, while non I-SEM capacity providers (generation, demand, and storage) would not directly receive any remuneration. Each interconnector would be subject to a specific de-rating factor, reflecting the extent to which it is expected to support the I-SEM at times of scarcity.

2.4.6 We consider below the Performance Based and Availability Based variants of the Interconnector Led Approach.

Interconnector Led Performance Based

2.4.7 Under this variant:

- The relevant interconnector would be able to bid for Reliability Options at its de-rated capacity; and

[14] Non-I-SEM capacity providers would earn the energy price in their resident market. This price could rise if there was scarcity in the I-SEM.

- The contracted and actual flows across each interconnector would be assessed to see whether they gave rise to any difference payments under the relevant Reliability Option.

2.4.8 A key issue with this approach is that the interconnector asset owner would not receive payments from the I-SEM energy market necessary to cover the difference payments in the event that the Reliability Options were called (regardless of whether cross border flows were delivered or not). This is because the interconnector only receives the expected Day Ahead price *differential* between the GB and I-SEM markets through the sale of FTRs and is required to pass on the actual price differential (i.e. the congestion rent) to FTR holders. In addition, should scarcity event emerge during the intra day or balancing timeframe, the interconnector would be exposed to the difference payments[15].

2.4.9 The corollary of this is that interconnectors under this approach would be required to fund any shortfall in difference payments through their option fee in the CRM auction or through FTR revenues. This may dull any incentives under the CRM to build new interconnection and also impact negatively on consumers who have funded the existing interconnectors.

2.4.10 A further complexity of this approach for the I-SEM CRM is the allocation of contracted flows to specific interconnectors. As discussed in 2.5 below, it is possible to quantify the total contracted flow between the I-SEM and its neighbours at each of the day-ahead, intra-day and balancing stages – and this quantification will be required to settle the Balancing Market. The Settlement of the Reliability Options will require the allocation of those contracted flows to the specific interconnectors – a step that may not be required for Balancing Market settlement. There are a number of approaches that can be taken to this allocation, including:

- **Balance interconnector utilisation:** This approach would allocate the flow between EWIC and Moyle to achieve the same percentage utilisation on each interconnector. This approach approximates the way power would flow in a DC circuit, assuming that:
    - The relative electrical resistance of the interconnectors is proportional to their relative capacity; and
    - That power flowing from the non-I-SEM producer faces an equivalent electrical resistance to get to either of the EWIC or Moyle interconnectors.
- **Pro-rata to meter:** This approach would allocate contracted flows between EWIC and Moyle in proportion to their respective metered flows. This approach will

[15] FTRs expire at the DA stage under the European Target Model and interconnectors currently have no means of capturing congestion in the intra day and balancing timeframes. The CACM Regulation requires congestion pricing at the ID stage but no method that is compatible with continuous trading has been developed. The current draft of the Electricity Balancing Network Code envisages that, under cross border balancing arrangements any accepted offer or bid is paid at the price in the accepting balancing market leaving no difference in prices to be captured by the interconnector asset owner.

achieve the correct allocation where those flows are driven by factors outside the control of the interconnectors – as then the power flows (as measured by the meters) are driven by the physical characteristics of network components as well as whether producers and consumers in each market perform as contracted.

- **Complex Power flow modelling:** This approach would carry out detailed power flow modelling to determine how power should have flowed across each interconnector. This approach would be highly complex and go well beyond the approaches being considered for market coupling.

Interconnector Availability Approach

2.4.11 Under this variant the interconnector similarly bids into the I-SEM CRM but is only required to be available to deliver energy into the I-SEM when the Reliability Option is called to avoid having to pay difference payments. Hence, the incentive for the interconnectors is only dependent on their own reliability and not the actual power flows between the markets.

2.4.12 The options avoids the issue with the Performance Based approach outlined above by exempting interconnectors from making difference payments providing that they are available. It would also avoid the complexity of calculating the contribution of outturn flows between the different interconnectors.

2.4.13 This option would means that interconnectors receive the options fees in the I-SEM CRM up to their full de-rated capacity and hence would incentivise further investment in cross border transmission capacity but in effect passes the risk of non-delivery to consumers.

2.4.14 A number of further issues with both interconnector led approaches include:

- **Non-I-SEM Capacity investment:** The interconnector led approach does make payments to those that provide physical interconnection between the I-SEM and its neighbours and therefore provides incentives for investment in further interconnection between the I-SEM and the rest of the EU Internal Market.

- If, however, no signal was provided for investment in non I-SEM capacity other than interconnection, long run investment signals could be undermined. One means of dealing with this would be for interconnectors to back off the risk of capacity shortages through contracting with non-I-SEM capacity providers. These payments could provide appropriate incentives for investment in non-I-SEM capacity; however there are a number of factors that frustrate these incentives.

The interconnectors would benefit if a new power station was built in GB and if this increased the contribution of the interconnectors to the I-SEM capacity requirement. This would be reflected through changes to the de-rating factor for the interconnectors – increasing their potential revenue from Reliability Option

Fees. Potential for higher option fees could then be used to support investment through the interconnectors contracting with the relevant GB capacity.

However, there are a number of factors that would act to prevent or otherwise complicate this up-stream contracting by the interconnectors:

- **EU Third Energy Package:** as Transmission System Operators, the EWIC and Moyle asset owners and any future interconnectors are precluded from having any interest in Generation or Supply[16];
- **Risk of free-riding:** The hypothetical GB generator in the above example is likely to deliver benefits to both of the existing interconnectors. For optimal investment, both would need to contract with non I-SEM capacity providers (generation, storage or demand side). Those interconnectors that do not invest will get the benefit of increased Reliability Option fees for free.

FTR Led Approach

2.4.15 The FTR led approach is similar to the Interconnector led performance approach, save that it is the owner of the FTRs arising from an interconnection (rather than the asset owner) that participates in the I-SEM CRM.

2.4.16 Whilst this approach partially addresses one of the issues with the Interconnector led approach (i.e. the Third Package prohibition on TSOs having an interest in generation or supply), it may raise or compound some other issues. However, this option may ensure incentivisation of interconnection and cross border providers as there would be increased demand in the annual FTR auctions which should clear at a higher price, since the FTR holder not only receives the day-ahead congestion rent, but also has the opportunity to receive the CRM option fee, if successful in the CRM auction.

2.4.17 The **issue partially addressed** by the FTR approach relates to having revenue to offset the Reliability Option difference payments. The owner of the interconnector asset will, in the first instant, get a payment based on the difference between the GB and I-SEM prices (i.e. the congestion revenue). This payment is then passed to the holder of FTRs; however it may still be insufficient to cover the cost of Reliability option difference payments (e.g. if price in GB is also high (higher than the RO strike price) or the Reliability Option is called in the intra day or balancing timeframe).

2.4.18 The **issue compounded** by the FTR approach relates to up-stream investment, with a number of factors combining to make it less likely that this will support appropriate investment in non-I-SEM Capacity, with a greater risk of free riding. FTRs are likely to be owned by a number of parties – each of which would have to contribute to the upstream

[16] Article 9, paragraph 1(b), European Directive 2009/72

investment for an optimal solution. These parties will be difficult to identify, as the timescales for the release of FTRs to the market is likely to mean

- They are released after the decision to build a plant; and
- That they may be traded several times between their initial release by the interconnectors and their expiry at the day-ahead stage.

2.4.19 The **additional issues** introduced by the FTR approach are as follows:

- **Availability at capacity auctions:** The European regulations require that interconnector transmission rights (including FTRs) are released to the market over various timescales - including an annual auction of year-long FTRs, and monthly auctions of month long FTRs. At each auction to release FTRs, if there is to be a subsequent auction for FTRs covering the same time period (e.g. an auction of FTRs for the year 2021 would be followed by separate auctions for each of the months in 2021) the interconnector is required to hold back some capacity to be released at those subsequent auctions. This means that:
    - For capacity auctions held a number of years in advance, there are likely to be few (if any) holders of FTRs that can participate in that auction;
    - For capacity auctions held a year in advance, it is possible that some holders of FTRs will exist; however, the FTRs will not cover the full interconnector capacity – as some will have been retained by the interconnectors for subsequent auctions.
- **Allocation of Day Ahead flows:** the allocation of aggregate cross border flows between participants is informed by the quantity of relevant FTR each holds at the day ahead stage[17] as follows:
    - In most cases, each participant's will be allocated a cross border day-ahead flow to match the quantity of its relevant FTRs;
    - Where necessary, each participant's allocation of cross border capacity will be reduced pro-rata to match the relevant aggregate cross border flow arising from the day-ahead market.
- **Allocation of remaining flows:** FTRs mature at the day-ahead stage, so do not have the potential to impact the allocation of flows arising from later (intra-day and balancing) trades. This implies an allocation of aggregate cross border flows to specific participants on a pro-rata basis. This allocation will be pro-rata to the Reliability Option quantities held by each participant. There are a number of options for how this Reliability Option quantity is defined:
    - **Gross:** allocation is pro-rata to the total quantity of Reliability Options held by each relevant participant.

[17] The settlement of FTRs will need a register of who owns those FTRs, so that payment can be made.

- **Net:** allocation is pro-rata to the total quantity Reliability options held by each relevant participant *net* of any allocation arising from earlier (e.g. day ahead) trades.

Some of these issues may be addressed by only requiring FTR holders to pay difference payments in the I-SEM at the DA stage, effectively meaning that this approach becomes availability based for the ID and Balancing timeframes[18].

Provider Led Approaches

2.4.20 Under the provider led approach, the non-I-SEM participants in the I-SEM CRM are providers of capacity that:

- Is physically located outside the CRM; and
- Can show there is a physical path from their capacity to the I-SEM electrical system.

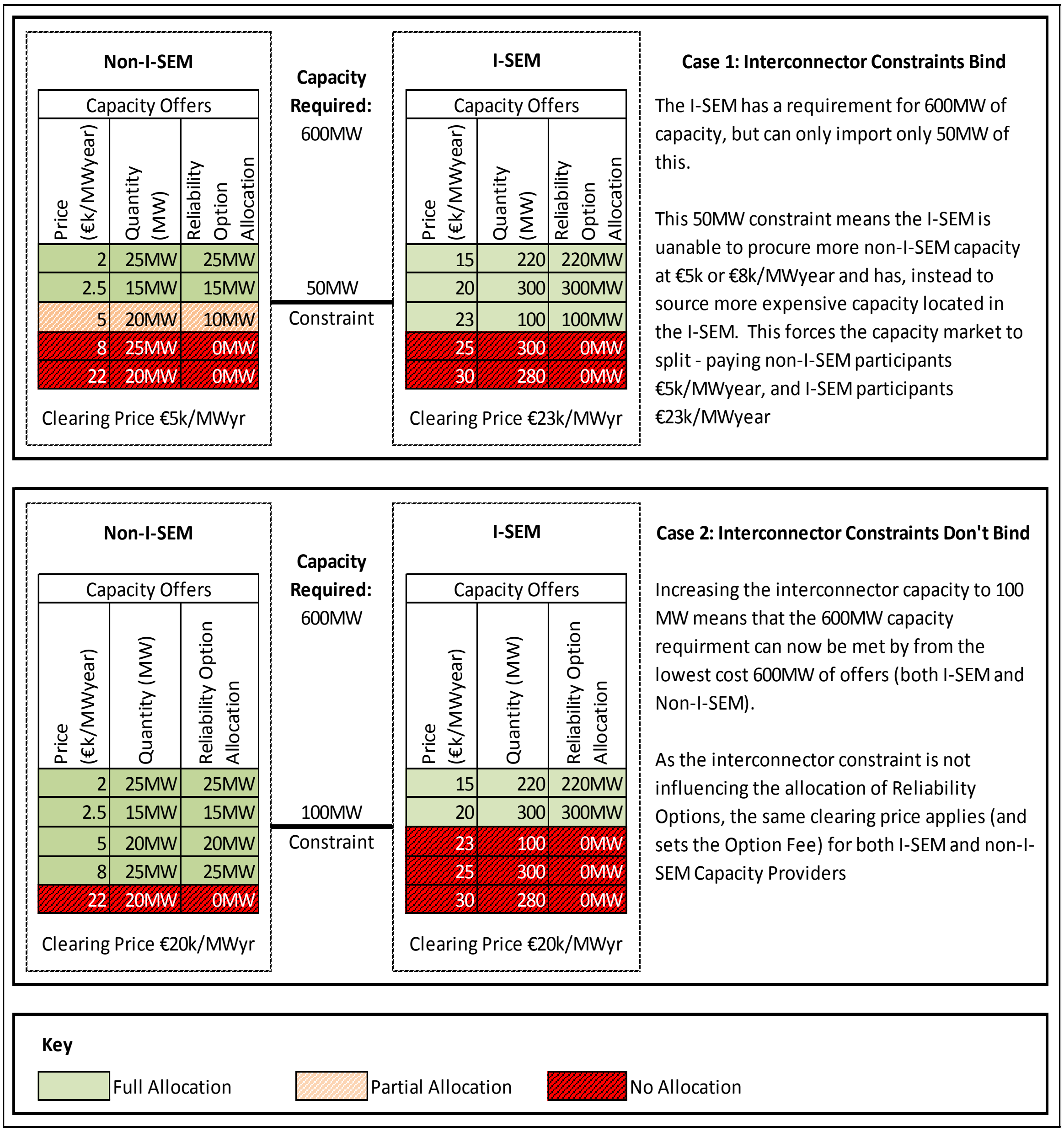
2.4.21 This approach would necessitate the potential for a multi-zonal approach to the auctions to release I-SEM Reliability options. This could set a different option fee for providers located in the I-SEM and those located outside the I-SEM though the same trigger (i.e. strike price) would apply to all providers. Markets normally split into zones where a transmission constraint prevents lower cost providers in one zone from meeting the requirement in an adjacent higher cost/price zone (see Figure 5). An external (GB) zone in the I-SEM capacity auction would likely clear at lower level to the I-SEM for a number of reasons:

- **Competition:** More supply than demand in the external zone may mean that interconnection rather than GB generation capacity could be the scarce resource.
- **I-SEM capacity low cost for GB baseload generator:** There are a number of reasons why the I-SEM capacity mechanism may be an attractive source of incremental revenue for non-I-SEM providers, without imposing significant incremental costs on those providers. For example, a GB baseload generator faces a low risk of not generating at times when an I-SEM Reliability Option could give rise to difference payments; and
- **Transmission Constraint**: GB baseload demand is greater than 4GW[19], compared to 1GW interconnection capability between GB and the I-SEM.

[18] This would ensure that FTR holders with physical positions in GB would be equivalent to I-SEM capacity providers up to the Day Ahead stage. Should the RO be called in the I-SEM at the ID or Balancing timeframes, the difference payments would not apply as there would be no way for the FTR holder to capture this revenue in the I-SEM.

[19] National Grid, Weather Corrected Demands, March 2015: http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-explorer/

Figure 5: Example showing how capacity market could split for allocation of Reliability Options

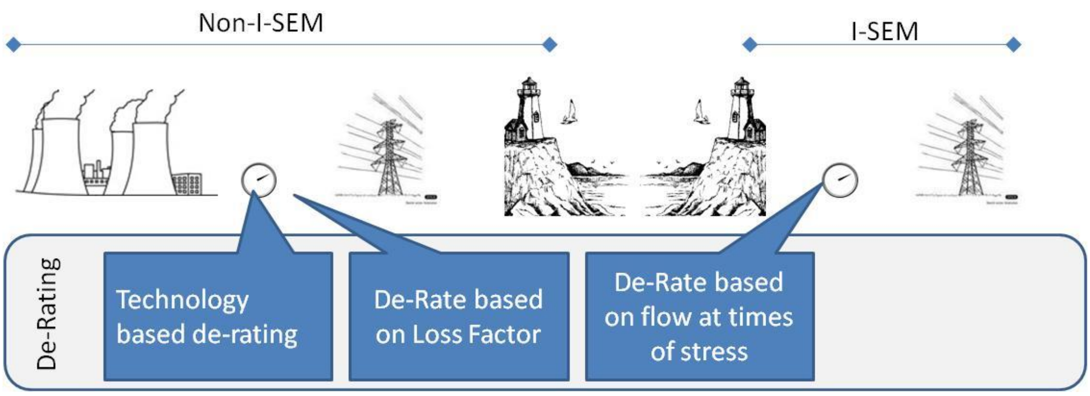


2.4.22 Under this option, the actual capacity from each provider would be de-rated by multiple factors, and ultimately impacted by a constraint on how much non-I-SEM Capacity is expected to contribute to the I-SEM generation security standard. – as shown in Figure 6. These factors are:

- A technology de-rating factor – based on the factors applied to similar technologies that are located in the I-SEM;
- A non-I-SEM losses factor, to cover electrical losses between the relevant capacity and the electrical boundary of the I-SEM (in this case, the location of the I-SEM settlement meter for the relevant interconnector); and

- An interconnector constraint, reflecting the extent to which the interconnector(s) are expected to support the I-SEM system at times of system stress[20].

Figure 6 : De-rating factor components for the provider led approach



2.4.23 To settle Reliability Options under a provider led approach, we need to allocate the total flow between the I-SEM and adjacent markets (see 2.3 above) between specific providers at each of the day-ahead, intra-day and balancing stages. There is potentially a significant amount of additional information that can be used to inform the allocation of flows between providers. This includes:

- **FTRs:** Any relevant FTRs held through to maturity by the relevant provider;
- **Meter:** The metered output of the relevant provider; and
- **Local Trades:** Any trades where the relevant provider has bought or sold power in its local day-ahead, intra-day or balancing market.

2.4.24 There are two broad ways in which this information can be used for the allocation of flows to providers, leading to two variants of the provider led approach:

- **Performance based:** Performance is assessed based on actual flows at the relevant interconnector(s) as well as at the relevant provider's meter; and
- **Availability Based:** Performance is assessed based on the relevant provider's availability to perform at the relevant time (e.g. by having offers to generate in all relevant energy markets within its Member State.

Performance based

2.4.25 The Performance based Provider Led approach allocates interconnector flows to non-I-SEM participants such that at times when Reliability Option difference payments are being made:

- There is appropriate treatment if the interconnectors fail to deliver their contracted capacity, such that:

[20] Note, this "Constraint" will have the same value as the Interconnector De-Rating Factor used in other approaches.

- I-SEM consumers are appropriately compensated for the lack of delivery and receive value for money; and
- Non-I-SEM providers do not face incentives weaker than those faced by those in the I-SEM; and

- Non-I-SEM capacity providers have similar risk management opportunities (at the day-ahead stage) to those available to I-SEM Capacity providers.

2.4.26 The measurement of non-I-SEM providers contracted flows across the I-SEM markets would then be similar to that for the other approaches for the treatment for cross border capacity:

- **Allocation of Day Ahead flows:** Similar to the FTR approach, the allocation of aggregate cross border flows between participants is informed by the quantity of relevant FTR each holds at the day ahead stage[21] as follows:
  - In most cases, each participant's will be allocated a cross border day-ahead flow to match the quantity of its relevant FTRs;
  - Where necessary, each participant's allocation of cross border capacity will be reduced pro-rata to match the relevant aggregate cross border flow arising from the day-ahead market;
  - Where necessary, each participant's allocation of cross-border capacity will be reduced for each participant's share of any short-fall in the ultimate physical flow into the I-SEM.

- **Allocation of Intra-Day and Balancing Market Trades:** When market coupling is fully effective, it is expected that intra-day and balancing markets trades will give rise to incremental cross-border flows in line with the cross zonal price differentials. The parties to those trades will not, however, be aware that they have been party to a cross border trade. They will have sold (or purchased) power in their local market, and not be aware that the ultimate counterparty to that trade was located in another market. It is unclear at this point as whether it will be possible to identify these "cross border" trades; however, if it is possible, there are a number of options for how trades in these timescales are allocated to participants:
  - **As traded**: Based on actual cross-border trades in the relevant markets – where the non-I-SEM provider was a counterparty to that trade;
  - **Pro-rata to Reliability Option**: This would be the same as the FTR approaches set out in 2.4.15 above, with a net (adjust for earlier trades) and gross (no adjustment for earlier trades) options;
  - **Ignore**: Any Reliability Option quantity held by a non-I-SEM participant is settled against the Balancing Market price;

[21] The settlement of FTRs will need a register of who owns those FTRs, so that payment can be made.

- **Allocation of Delivery Shortfall:** If physical flow into the I-SEM is less than that contracted through the relevant Reliability Options, this shortfall is , allocated across the relevant non-SEM participants as follows:
    - **First on provider meter**: Any shortfall is first allocated across those providers with a metered production less than their Reliability Option contracted quantity (after appropriate adjustment for losses).
    - **Balance pro-rata:** Any remaining shortfall is then allocated pro-rata across all non-I-SEM capacity providers, in proportion to their contracted Reliability Option quantity

Availability Based

2.4.27 As with the Provider Led Performance Based approach, this approach would involve capacity providers located outside the I-SEM bidding zone participating in the I-SEM CRM auctions with the auction clearing at a separate (GB) zonal price. The major difference between this and the Performance based approach is that the obligation on non I-SEM capacity providers is availability rather than deliverability based. That is, non-I-SEM capacity providers are subject to penalties (i.e. Reliability Option difference payments) only for failure to generate or offering to generate and not related to the flows on the interconnectors.

2.4.28 In the I-SEM CRM the cross border availability based model could operate with an obligation on non I-SEM capacity provider to place an offer into its local coupled market (in the first instance the GB market). Given that there will be FTRs between the I-SEM and GB market and no forward physical nominations, the issue of nomination of flows outside market coupling does not arise and the full Available Transfer Capacity of the two interconnectors should be available for the market coupling algorithm. Therefore the obligation would take the form of a requirement to offer into the GB DAM.

2.4.29 Should the capacity provider's offer into the GB DAM not be accepted, then these providers would be required to offer into the IDM and then the Balancing market. Regarding the level of the offer, again the obligation would require that this was in a 'reasonable' range, reflecting SRMC and anticipated scarcity.

2.4.30 If the non I-SEM capacity provider does not bid and the Reliability Option is called in the I-SEM then the capacity provider would be required to pay the full difference payments, including the ASP should ASP be triggered in the I-SEM. The impact of these full difference payments would be limited by any stop-loss limits incorporated within the Reliability Options.

Provider Led – Benefit and Issues

2.4.31 The direct participation of non-I-SEM capacity providers make these the best approaches for providing incentives to invest in up-stream capacity and therefore may rank better in terms of not distorting long run investment signals in the internal market; however, they are not without issues particularly in terms of practical implementation. Notable issues are:

- **Double Payment:** The non-I-SEM capacity provider could receive payments from the I-SEM as well as from other CRMs. With fully aligned capacity markets across Europe, this would not necessarily be an issue, and may act to reduce the overall costs of capacity. As and when new capacity is required, any prospective new plant would consider the revenue it would get from other markets (energy, ancillary services and other CRMs) in forming its bid into the I-SEM CRM. Similarly, existing capacity would be able to reduce its bids into the I-SEM CRM based on its assumed revenue from other CRMs[22].
- **Delivery assurance:** The fact that participants can participate in multiple CRMs may be less of an issue if each such CRM can assure itself that the relevant capacity is acting to support its system, rather than those elsewhere. This is achievable for the I-SEM using the approach suggested above – where any shortfall in metered flow across the I-SEM interconnectors is allocated across all non-I-SEM participants. This solution works for the I-SEM as a market which is only connected to one other price zone (GB). It is more complicated for a "transit" country to verify that external capacity has actually supported its system. For example:
    - Consider a generator located in Northern France, that had contracted to provide capacity to both the GB and I-SEM systems
    - If electricity is imported to GB from France, and exported from GB to the I-SEM, in which price zone (GB or I-SEM) was the energy produced by the French capacity consumed?
- **Access to participant meter data:** Under the Performance based variant**,** the settlement of Reliability Options for non-I-SEM participants would need access to settlement quality meter data for those participants. Getting access to this data will require further with the relevant parties.
- **Determination of loss factors:** This approach requires the determination of loss factors to account for losses between the provider and the I-SEM. The determination of these loss factors requires data on the physical characteristics of networks outside the I-SEM – data that is not necessarily in the public domain.
- **Implementation**: These options would require EirGrid and SONI to develop with National Grid a potentially complex and costly cross border system to facilitate potential GB capacity providers participating in the I-SEM CRM. The administrative burden and costs of such a system may outweigh the benefits when compared with other options.

[22] Note: to be considered as "new investment", the building of capacity outside the I-SEM would have to increase the contribution of interconnectors in meeting the I-SEM security standard. Any new plant that did not deliver this would not be eligible for contracts longer than a year from the I-SEM CRM.

Hybrid approach

2.4.32 The Hybrid option involves non I-SEM capacity providers bidding to get access to the interconnector capacity between their local market and the I-SEM up to the de-rated level of that interconnector.

2.4.33 Non I-SEM Capacity providers would receive the clearing price of a zonal auction (which if interconnection capacity is scarce should clear at a lower value than the I-SEM zonal capacity clearing price) and pay difference payments if not delivering energy into their local market when the Reliability Option is called. The interconnector subsequently bids into the I-SEM CRM auction, receives the ISEM clearing price for any accepted capacity, but pays the non I-SEM capacity clearing price to the winning non I-SEM capacity providers. Hence, the interconnector would receive the difference between the I-SEM auction clearing price and the zonal auction clearing price and be liable for difference payments only if unavailable. The non I-SEM capacity providers would also be responsible for difference payments based on their respective performance, this could be based on an availability (bidding into the market) or performance based model (flows over interconnector).

2.4.34 The option effectively splits the revenue for cross-border capacity between external providers and the owners of the physical interconnectors. In all cases this means that external capacity providers do not make any difference payments when:

- There is a shortfall in energy imported to the I-SEM (such that import is less than the Non-I-SEM capacity contracted through Reliability Options; and
- That shortfall is a direct result of a technical failure on one or more of the interconnectors linking the I-SEM to an adjacent market.

2.4.35 In the above cases, responsibility for the relevant difference payments should lie with the relevant Interconnector. This implies a need to split the rights (to receive Option Fees) and obligations (to make difference payments) between external providers and interconnectors. This can be achieved through an explicit or implicit[23] auction mechanism.

- **Implicit auction** model allocates revenue between the interconnector and non-ISEM generators as part of the main capacity auction. This would need to be designed and implemented centrally.

- **Explicit auction** model the interconnector bids directly into the capacity market auction, if successful it will receive capacity payments but will hold related obligations. The interconnector could auction its de-rated capacity to non-ISEM generators; this could be done in advance to determine the marginal price to bid into capacity auction.

[23] "Participation of interconnected capacity in the GB capacity market, DECC, September 2014 and slide 8 of: http://www.eprg.group.cam.ac.uk/wp-content/uploads/2015/06/Mann_Presentation-to-EPRG-final.pdf

2.4.36 Under the implicit auction model approach Reliability Options are, in the first instance, allocated in line with the Capacity provider approach. Non-I-SEM (e.g. GB) capacity providers would offer capacity into I-SEM Capacity Auction and (subject to the interconnection constraints) compete directly with I-SEM capacity providers for Reliability Options. As shown in Figure 7, the interconnector constraint may restrict the extent to which Non-I-SEM (e.g. GB) capacity can be utilised for the I-SEM Generation security standard.

2.4.37 Case 1 of Figure 7 shows the market splitting as a result of the interconnector constraint. In this case:

- Non-I-SEM (e.g. GB) capacity providers get paid a lower option fee – in this case €5k/MWyear. This option fee is set at the clearing price for the Non-I-SEM (GB) zone. This clearing price reflects the highest offered option fee that was accepted for in the I-SEM Capacity Auction from capacity providers located in the Non-I-SEM (e.g. GB) zone.

2.4.38 I-SEM capacity providers get paid a higher option fee – in this case €23k/MWyear. This option fee is the clearing price for the I-SEM zone. This clearing price reflects the highest offered option fee that was accepted in the I-SEM Capacity Auction from capacity providers in located in the I-SEM zone. The market splitting shown in Case1 of Figure 7 occurs because of limitations in the interconnection between the I-SEM and its neighbours. As is shown in Case 2, market splitting is not required when the level of interconnection does not impact the choice of capacity providers (i.e. the constraint does not bind). In this case there is no need for market splitting – and so is a single capacity price zone covering both I-SEM and non I-SEM capacity providers.

Figure 7: Market splitting and benefit of trade

Case 1: Interconnector Constraints Bind

Non-I-SEM

Capacity Offers

Price (€k/MWyear)	Quantity (MW)	Reliability Option Allocation
2	25MW	25MW
2.5	15MW	15MW
5	20MW	10MW
8	25MW	0MW
22	20MW	0MW

Clearing Price €5k/MWyr

Capacity Required: 600MW

50MW Constraint

I-SEM

Capacity Offers

Price (€k/MWyear)	Quantity (MW)	Reliability Option Allocation
15	220	220MW
20	300	300MW
23	100	100MW
25	300	0MW
30	280	0MW

Clearing Price €23k/MWyr

The I-SEM has a requirement for 600MW of capacity, but can only import only 50MW of this.

This 50MW constraint means the I-SEM is uanable to procure more non-I-SEM capacity at €5k or €8k/MWyear and has, instead to source more expensive capacity located in the I-SEM. This forces the capacity market to split - paying non-I-SEM participants €5k/MWyear, and I-SEM participants €23k/MWyear

Case 2: Interconnector Constraints Don't Bind

Non-I-SEM

Capacity Offers

Price (€k/MWyear)	Quantity (MW)	Reliability Option Allocation
2	25MW	25MW
2.5	15MW	15MW
5	20MW	20MW
8	25MW	25MW
22	20MW	0MW

Clearing Price €20k/MWyr

Capacity Required: 600MW

100MW Constraint

I-SEM

Capacity Offers

Price (€k/MWyear)	Quantity (MW)	Reliability Option Allocation
15	220	220MW
20	300	300MW
23	100	0MW
25	300	0MW
30	280	0MW

Clearing Price €20k/MWyr

Increasing the interconnector capacity to 100 MW means that the 600MW capacity requirment can now be met by from the lowest cost 600MW of offers (both I-SEM and Non-I-SEM).

As the interconnector constraint is not influencing the allocation of Reliability Options, the same clearing price applies (and sets the Option Fee) for both I-SEM and non-I-SEM Capacity Providers

Key

Full Allocation | Partial Allocation | No Allocation

2.4.39 The market splitting under Case 1 leads to a benefit of trade of €900k/year - as shown in Figure 8. There are a number of options for what is done with this "benefit of trade". Notably:

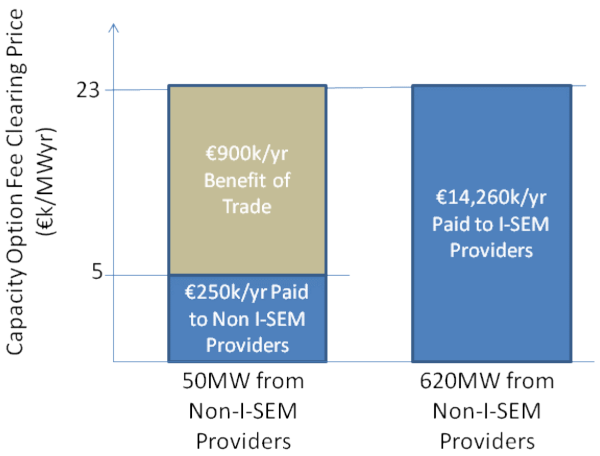
- **Give to I-SEM consumers:** Under all options, a charge is levied on Suppliers to cover the cost of capacity. Under this option, that Supplier charge only covers the blue areas shown in Figure 8. This has the effect of passing the full benefit of trade back to I-SEM consumers;
- **Oblige Interconnectors to accept – with obligations to pay**: Under this option the capacity charge levied on Suppliers covers all the costs (i.e. the blue and green areas) shown in Figure 8. Each Interconnector then enters into a partial Reliability

Option that requires it to make any difference payments that may arise when their asset is (wholly or partially) unavailable. The Option Fee each interconnector receives for this partial Reliability option reflects its (pro-rata to its de-rated capacity) share of the benefit of trade; or

- **Interconnectors are free to accept – with obligations to pay:** Each interconnector can opt to receive its (pro-rata to its de-rated capacity) share of the benefit of trade. In return for this payment, the interconnector is required enter into a partial Reliability Option that requires it to make any Reliability Option difference payments that may arise when their asset is (wholly or partially) unavailable. Under this option, the capacity charge levied on Supplier covers:
    - The payments to capacity providers (blue areas from Figure 8); and
    - Any payments to those Interconnectors that opted to take their share of the benefit of trade.

Where interconnectors do not choose to take their share of the benefit of trade, there will be a remaining balance of that benefit of trade. This remaining balance is used to reduce the capacity charge levied on Suppliers

Figure 8: Benefit of Trade



2.5 ASSESSMENT OF APPROACHES

2.5.1 The following summarises how each of the I-SEM assessment criteria are impacted by the various approaches set out for how the I-SEM CRM treats non-I-SEM providers of capacity.

- **Internal Electricity Market *and* Competition:** The overarching EU internal market framework is that Member States should not discriminate between domestic and cross border contracts (in this case – Reliability Options). The impact of each approach on this criteria is therefore very similar to that on the "Competition" criteria.

The approaches vary in terms of their impact on the ”Internal Electricity Market” and “Competition” assessment criteria, and the extent to which they support efficient competition between I-SEM and non-I-SEM Capacity Providers. Notably, this should lead to a rational choice over:

- Which option facilitates efficient investment in transmission capacity between bidding zones; and
- Whether to build new (or retire old) capacity physically within the I-SEM, or in the electricity markets of other member states.

The impact of this on the different approaches is set out below:

- **Net off demand – Implicit:** The value of non-I-SEM capacity is only evident through the difference between I-SEM and neighbouring energy prices, and through the value of FTRs. The I-SEM CRM would not explicitly value these non-I-SEM providers.
- **Interconnector or FTR led – Implicit:** Both these approaches do allow for the payment of Reliability Option fees in respect of interconnection; however, the bulk of the value of the interconnector is based on the difference in energy prices at its respective ends. Whilst this value may provide a case for more investment in interconnectors, that case is based on the energy market – and may not be significantly enhanced by the allocation of Reliability Options. However, should new interconnection participate in the CRM Auction, the extra revenue and potentially longer term contract may have a significant impact on the cost of financing and the investment decision.
- **Provider led – Explicit for generation, implicit for interconnectors:** Both variants of the “provider led” approach allow providers (e.g. generators) located outside the I-SEM to directly compete with those inside the I-SEM. As these approaches incorporate a zonal capacity price, they will also create a clearer signal of the value of increased interconnection, if that interconnection would provide access to more “low cost” capacity located outside the I-SEM.
- **Hybrid – Explicit:** This option retains the same benefits as the “Provider led” approaches in allowing capacity providers located outside the I-SEM to directly compete with those inside the I-SEM. In addition, it provides the opportunity for interconnectors to gain revenue reflecting the value they add in providing access to lower cost capacity. This additional revenue could support increased investment in interconnection.
- The **interconnector led and hybrid approaches** may increase the potential for conflicts of interest regarding the role of EirGrid as owner and operator of the East West Interconnector and new functions as Delivery Body for the I-SEM CRM.

- **Security of Supply:** All of the approaches will procure sufficient capacity to satisfy the I-SEM security standard. Any difference between the approaches relates to how they account for and incentivise the reliability of that capacity. De-rating of interconnector capacity will apply to all approaches, providing an opportunity to account for the expected reliability of interconnectors; however, they differ in the strength of the incentives to deliver that capacity when required:
  - **Net off demand :** The "net off demand" approach does not award any Reliability Options in respect of non-I-SEM providers, so does not provide any incentives (over and above those in the energy market) for delivery when required
  - **FTR Led** : The FTR led approach will lead to the application of the Reliability option at the day ahead stage, but not in intraday and balancing market timescales over and above ability to capture higher balancing market price depending on what is in the interconnector. These latter market timescales are arguably more critical – as scarcity tends to occur at or shortly before physical delivery. In addition to the weakness in terms of the markets covered by the FTR, the FTR is a financial product – there is no guarantee that the holder of the FTR will have any influence over physical delivery.
  - **Interconnector Led:** The interconnector led approaches provides very strong incentives to the interconnector asset owner to perform – and maintain the availability of its interconnection asset. The key weakness of this approach (for Security of Supply) is that interconnector availability is but one of the reasons why it could fail to provide support when required. The lack of delivery may be because of a lack of generation or transmission capacity in the systems that feed that power to the interconnector for transport into the I-SEM. Restrictions on interconnectors (as TSOs) taking an interest in generation limit the ability of an interconnector to contract up-stream generators to cover (at least part) of that risk which is outside its control.
  - **Provider Led:** The provider led approaches do place Reliability Option incentives on non-I-SEM participants (e.g generators) in the Day Ahead and Balancing Market timescales. The provider led options will impact Security of Supply when the relevant interconnectors are technically available, but flow less power into the I-SEM than contracted through relevant Reliability options. This could happen because of a shortage of generation in the adjacent (e.g. GB) market. This, in turn, could have been caused by a shortfall in the output from one or more of those non-I-SEM providers.
  - The delivery based variant will clearly identify the non-I-SEM participants that have under-delivered and seek appropriate payments from those providers. The availability based approach is weaker in identifying non-I-SEM participants that have under delivered. This weakness arises from a

number of factors – including difficulty in allocating company to company trades (as occur in GB) to specific units, and difficulty in identifying whether participants are genuinely available. For example, experience of availability CRMs in the US has shown generators can structure their offer data so that they appear available, but do not actually run when required.
  - **Hybrid:** The Hybrid option generally impacts Security of Supply in a similar way to the Provider Led options - though the Hybrid Option imposes a penalty on the interconnector if it is not technically available when the RO is called and so may rank higher on Security of Supply.

- **Equity:** The Hybrid option paired with the Performance Based variant of the Provider Led are the strong in terms of equity – as:
  - Non-I-SEM providers face delivery incentives very similar to those for I-SEM participants; and
  - This approach recognises the contribution of Interconnectors in providing access to low-cost non-I-SEM capacity and incentives them to be available.

The other approaches may lead to inequities in terms of providing performance incentives in fewer of the I-SEM markets, or not paying for the capacity. In particular, these inequities may relate to:

  - **Availability Based variant of Provider Led and Interconnector Led:** At the Day Ahead stage external providers face similar incentives to those located in the I-SEM. In the availability based provider led approach the key difference is that external providers do not make a difference payment if the interconnector is technically available, but there is an actual shortfall in imports. If the external providers were "available" to produce, I-SEM consumers will have paid for capacity that wasn't delivered when required, and they will have received no compensation for that non-delivery. Equally in the availability based interconnector led approach if the interconnector was technically available they would face no difference payments if there was an actual shortfall in imports.
  - **Performance Based Interconnector Led** – this option places a high risk on interconnectors who are unable to access I-SEM energy revenue to cover difference payments.
  - **Net Off Demand:** Under this approach external parties neither receive nor make Reliability Option payments
  - **FTR Led:** This approach only measures performance at the day ahead stage;

- **Adaptive:** The Performance based variant of the Provider Based approach is the weakest in terms of adaptability. This option works at present because the I-SEM is a single price zone which is only connected to one other (GB) price zone. This could change due to market splitting, or if new interconnectors meant the I-SEM was connected to other (e.g. France) price zones. If either of these occur, it will be difficult or impossible to assert that capacity that was imported across an interconnector was used to support capacity in the importing zone, and not "wheeled" to a neighbouring price zone.

All other options are broadly similar in terms of their impact on the adaptive criteria. However, the adaptability of the ultimate solution for I-SEM is inextricably linked to the enduring EU solution for the participation of out of market or foreign capacity in CRMs.

- **Practicality and Cost:** Practicality and cost issues arise relating to the two provider led approaches and similarly impact the hybrid approach, whilst the other three approaches should be relatively simple to implement. The issues with the provider led data relate to the availability of data from the neighbouring market, notably:
    - **Meter data**: The "Performance based" variant assumes we can access settlement quality, half-hourly, meter data for the external provider
    - **Availability – access to data**: The "Availability Based" variant assumes we can access data to establish that the external provider has offered its power into the day-ahead, intraday and balancing markets in a usable form. This requires data sharing from the relevant NEMOs and System Operators to provide confidence that the data provided is accurate. This will be further complicated for GB participants – who may have sold their output many years ahead through bilateral (and private) contracts.
    - **Availability – Interpretation of NEMO data:** In a number of EU markets – including GB, trading at the day ahead and intraday stages is on a company (as opposed to unit) basis. In addition, GB participants are able to sell physical power in advance of the day-ahead market – meaning we would have to look for additional evidence (such as Physical Position Notifications) for evidence of their trade.

2.5.2 The following criteria are not impacted by the choice of approach:

- Environment
- Stability

Next Steps

- The RAs will continue to develop their thinking on these options at an EU level with colleagues in ACER and at the regional level with DECC and Ofgem in GB.

2.6 CONSULTATION QUESTIONS

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

A) Which of the approaches to the treatment of cross border capacity do you prefer and why? (For the Provider Led and Interconnector Led approach, please specify whether you prefer the "Performance based" or "Availability Based" variant).

B) Should the de-rating of interconnectors be based on historic performance, or include forward modelling to project how its performance could change in the future?

C) If there is a preference for the "Interconnector led performance based" approach there will be a need to allocate total interconnector flows between specific interconnectors. Which of the specific approaches set out in 2.4.6 do you prefer? These approaches were:

- Balance interconnector utilisation;
- Pro-rata to interconnector metered flow; and
- Complex power flow modelling

D) If there is a preference for the "FTR led" approach, which of the specific approaches set out in 2.4.15 (net or gross) do you prefer for the allocation of non-day-ahead flows?

E) If there is a preference for the "Performance based Provider Led" approach, which of the specific approaches set out in 2.4.25 do you prefer for the allocation of intra-day and balancing market trades?

- As traded
- Pro rata to Reliability Option (in which case – do you prefer "gross" or "net")
- Ignore – all in Balancing Market

F) If there is a preference for the "Hybrid" approach:

- Should this be paired with the "Delivery Based" or "Availability Based" provider led approach?
- Should Interconnector participation be mandated or voluntary?

Please provide a rationale for all of your responses.

3. SECONDARY TRADING

3.1 INTRODUCTION

3.1.1 Primary trading of Reliability Options will be via centralised auctions. This chapter considers:

- **The case for secondary trading**: Should the Reliability Option holder that acquires the Reliability Option at auction be allowed to trade its rights and obligations to a third party capacity provider (i.e. will secondary trading be allowed)?
- **Secondary trading market place**: Should the RAs require that the Capacity Market Delivery Body put in place a secondary trading platform, and should the RAs require that any secondary trading must take place on the secondary platform?
- **Limits on secondary purchasing:** Should a capacity provider be limited in the amount of capacity it is allowed to purchase in the secondary market, like in the auction, where it is limited to its de-rated capacity? GB is considering allowing a capacity provider to take on additional capacity obligations over and above de-rated capacity for limited periods.
- **Limits on secondary trading timeframes:** How soon after the auction and how close to (or even after) delivery can an obligation be traded?
- **Stop-loss limits and secondary trading:** a secondary acquirer of an Reliability Option should start from a zero position against the "stop-loss" limit, or whether the loss should transfer

3.2 CASE FOR SECONDARY TRADING

3.2.1 When a capacity provider is successful in a primary auction, it enters into a Reliability Option contract leading to a number of rights and obligations:

- The right to the capacity option fee; and
- The obligation to make difference payments when the Market Reference Price exceeds the Strike Price.

3.2.2 A Reliability Option holder may want to trade its rights and obligations to a third party capacity provider for a number of reasons, these include:

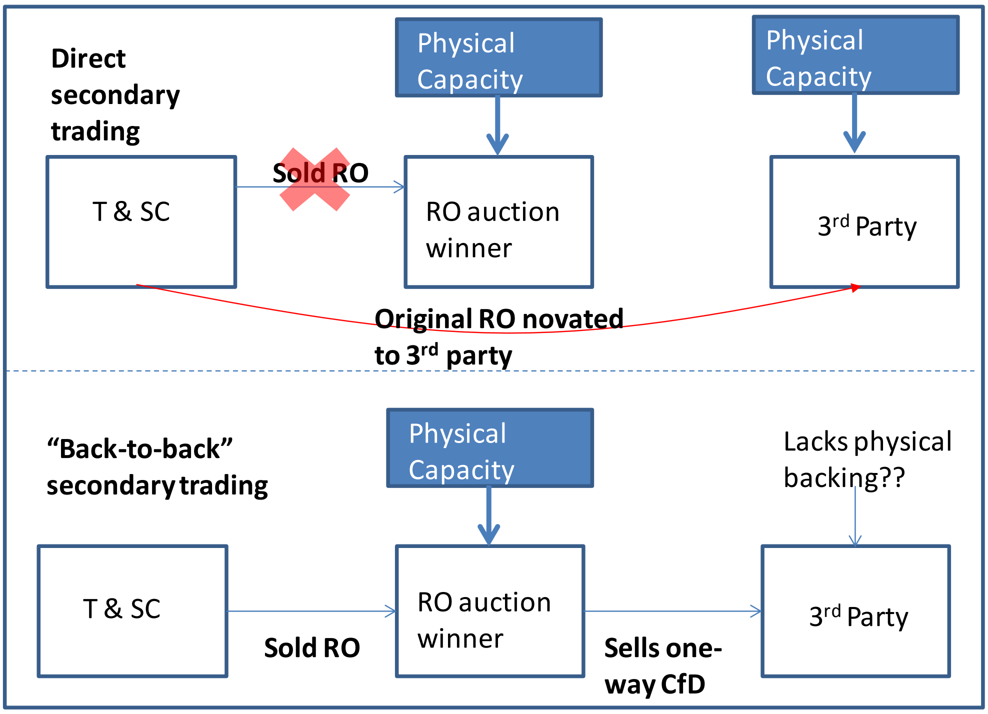
- When its plant is on temporary planned outage or is on prolonged forced outage;
- If plant reliability has degraded to a point whereby it no longer wants the exposure to difference payments;
- If its capacity is no longer economic and it wishes to close the plant;

3.2.3 This section discusses whether it is appropriate to allow the Reliability Option holder to pass on these rights and obligations to a third party via secondary trading. As illustrated in Figure 9, secondary trading could take different forms:

- **Direct secondary trading**. In this model, the Reliability Option holder, who has acquired the Reliability Option in the auction, sells the Reliability Option to a third party on the secondary market. The third party assumes all the rights and obligations of the original Reliability Option holder. The Reliability Option is novated to the third party, so that the third party now holds the Reliability Option directly with the T&SC, and the original Reliability Option holder is removed from the contractual chain[24]. Prior to the novation of the Reliability Option, the third party will need to have undergone the same pre-qualification process as the original auction participants[25]. This secondary trading of the Reliability Option could occur on an organised central Reliability Option secondary trading platform if one exists, or it could be negotiated bi-laterally between market participants;
- **"Back-to-back" trading**. In this model, the original Reliability Option holder lays-off its rights and obligations to a third party by buying a financial call-option (in the form of a one-way CfD). The Reliability Option holder negotiates with third parties to buy a one-way CfD, which has the same Market Reference Price, Strike Price, start and end date as the Reliability Option. It has therefore passed on its exposure to difference payments to the third party in the Non-Directed CfD market, and this is typically known as "back-to-back" trading. The original auction winner retains the contractual relationship with the T&SC, and has the obligation to pay the difference payments to Suppliers, although it expects to be able to recoup these payments from the third party. Note this is purely a financial trade; the third party has not undergone any pre-qualification process and may not be backed by physical plant.

[24] Although there may be some provision that continue, such as protection of commercially sensitive data
[25] We will need to review whether pre-qualification can happen throughout the year, or only immediately prior to an auction.

Figure 9: Forms of secondary trading



3.2.4 It may be argued that the potential for financial trading removes the need for secondary trading of the Reliability Option. However, there are a number of specific reasons why direct secondary trading may be a better option for the original Reliability Option holder than "back-to-back" trading. These include:

- **Credit risk.** With "back-to-back" trading, the original Reliability Option holder is exposed to the risk that the third party defaults on its obligations to make difference payments under the one-way CfD. The original Reliability Option holder will still need to make the difference payments to Suppliers even if the third party defaults, whereas in the secondary trading model, the Suppliers bear that default risk and the risk is managed by demanding appropriate collateral and via socialisation of supplier risk;
- **Market exit**. In the "back-to-back" model, the original Reliability Option holder retains the obligation to administer payments, and cannot exit the market completely. Whilst it may be able to exit by selling the asset and its payment administration capability as a going concern to a new owner, it could nevertheless constrain efficient market exit and entry; and
- **Complexities associated with split market approach**. A third party is unlikely to want to take on an option where settlement is dependent on whether the primary Reliability Option holder sells energy into the DAM, IDM or the BM.

3.2.5 Effects of "back-to-back" trading on overall system:

- **Systemic risk.** The MW volume of RO obligations traded "back-to-back" would represent a volume of MW which is no longer incentivised by RO difference payments to be generating during times of system stress, this could have negative effects on the security of supply.

3.2.6 The potential benefits listed above suggest that the I-SEM should include provision for direct secondary trading of Reliability Options. This direct secondary trading would not preclude financial trading of the rights and obligations arising from reliability options.

3.3 REQUIREMENT FOR A CENTRALISED SECONDARY TRADING MARKETPLACE

3.3.1 Direct secondary trading of Reliability Option could take place on an organised centralised secondary platform or solutions could be left entirely to the market to determine. Key options to consider are:

- **No Centralised Market:** This option leaves secondary trading entirely to the market. An organised market place (e.g. exchange, broker platform) may develop if market participants want it to, or trading could be entirely bi-lateral;
- **Optional Centralised Market:** This option establishes a centrally funded market place for secondary trading of Reliability Options, but does not preclude the emergence of competing market places, or the bi-lateral trading of Reliability Options.;
- **Mandatory Centralised Market:** This option establishes a centrally funded market place for secondary trading of Reliability Options. Only trades enacted on through that centrally funded market place will be recognised in the settlement of Reliability Options.
- **No Centralised Market for go-live:** This option would allow secondary trading in the market initially for go live of I-SEM. However a centrally funded market place for secondary trading of Reliability Options would be subsequently developed.

3.3.2 An assessment of these options against the I-SEM Assessment Criteria is set out below:

- **Competition:** The "mandatory centralised market" option will be best for competition, with no centralised market being worst. The creation of a centralised market will increase transparency over the secondary value of Reliability Options. This transparency will reduce new-entrant's uncertainty over future costs and revenues – ultimately leading to lower costs to consumers.

  Making the centralised market mandatory has further benefits in terms of increasing the confidence that all Capacity Providers will be able to trade their reliability options at an efficient price. It does this by:

  - Concentrating liquidity in one place; and
  - Forcing portfolio providers to trade to (e.g to cover outages) rather than internally transferring Reliability Options between their assets.

- **Stability:** The centralised market place options are inherently more stable than the alternative of leaving trading entirely to the market. Once a centralised market place is established, it is likely to endure; however, voluntary markets are not guaranteed.
- **Efficiency:** Trading for Reliability Options will enhance efficiency – regardless of which option is adopted. The efficiency of trading is arguably better in liquid markets; this would argue for the "mandatory centralised trading" option
- **Equity:** The choice of leaving secondary trading to the market or an optional centralised market may disadvantage smaller participants in the market.
- **Practicality/Cost: There** are a number of points against this assessment criteria:
    - There is a cost associated with the creation of a centralised market place; however, these costs do not need to be prohibitive. In the early days of Nord Pool, the forward market consisted of little more than a few phones and a white board;
    - Any centralised market will need to accommodate the range of trades that may be required by participants. This could include trade for a few weeks (e.g. to cover a planned maintenance outage) or for significantly longer periods (e.g. if a catastrophic failure causes a plant to close).

3.3.3 The following I-SEM assessment criteria are not impacted by the choice of market place:

- Internal Electricity Market;
- Security of Supply;
- Environment; and
- Adaptive.

3.3.4 We seek consultation feedback on:

- Whether there is likely to be sufficient demand for secondary trading to justify the cost of the development of a centrally organised platform;
- Which of the options for the secondary trading market place is preferred.
- Whether it needs to be ready at I-SEM go-live

3.4 LIMITS ON SECONDARY PURCHASING:

3.4.1 In the primary auction, a capacity provider cannot bid for Reliability Option volume in excess of its de-rated capacity. The key question is whether the same rule should be applied to secondary trading.

3.4.2 There might be a number of reasons to allow a capacity provider to be allowed to acquire more capacity obligation (i.e. Reliability Option volume, in the case of the I-SEM), than its de-rated volumes within the weeks approaching delivery. For example:

- In a “tight[26]” system the capacity headroom (between nameplate and de-rated capacity) is implicitly required to provide cover for plant that is unavailable (due to maintenance or otherwise)
- In the weeks approaching delivery, a capacity provider will know whether it has any planned maintenance outages over the relevant period;
- The output from intermittent plant is weather dependant and so seasonal. There are times of year when the expected output of the plant will be higher than average, meaning that plant may be prepared to provide more cover.

3.4.3 Although the certainty of plant availability will increase approaching delivery, the probability of forced outages will remain non-zero at all times of year. In addition, whilst intermittent plant may be more predictable 5 days ahead of delivery, allowing plant of any technology to acquire Reliability Options up to its nameplate capacity or Maximum Export Capacity is likely to overstate its potential contribution to alleviating scarcity.

3.4.4 DECC is currently consulting on a proposal to allow GB capacity providers to acquire additional capacity obligations in the secondary market up to the point where its total capacity obligation is equal to its Transmission Entry Capacity[27] or Connection Capacity (in the case of Proven Capacity for a DSU) for a limited period. If this proposal takes effect a capacity provider will be able to acquire this additional capacity obligation in the secondary market for a period from 1 day to 5 weeks, by trading in the secondary market from 10 to 5 business days before the start of the delivery period[28].The key concern in allowing a capacity provider to acquire Reliability Option volume in excess of its de-rated capacity is reliability- will it be able to deliver to its full nameplate capacity on a sufficiently reliable basis?

3.4.5 The SEM Committee seeks feedback from stakeholders on :

- Should capacity providers be restricted to their de-rated capacity in backing secondary trades of Reliability Options?
- If capacity providers are allowed to back secondary trades to a level above their de-rated capacity (i.e. the de-rated capacity restriction is relaxed):
  - Should their backing of those trades be capped by their nameplate capacity, name plate capacity as adjusted for forced outages, or something else?
  - How far in advance of delivery should the de-rated capacity restriction be relaxed (e.g.5 weeks ahead of delivery as proposed in GB)?
- Please provide a rationale for all responses.

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[26] Where installed capacity leaves little margin over that required to meet the security standard and hence maintain security of supply
[27] i.e. Maximum Export Capacity in SEM terminology
[28] See UK Department of Energy and Climate Change, CAPACITY MARKET: Consultation on reforms to the Capacity Market, 15D/457 15 October 2015

3.5 LIMITS ON SECONDARY TRADING TIMEFRAMES

3.5.1 The detailed design of secondary trading will need to consider a number of issues relating to trading timeframes, notably:

- **Standard Products:** Should the secondary trading of Reliability Options be based around:
  - **Standard products** – for example covering 1MW of cover for a defined week; or
  - **Custom products** – where the buyer and seller agree the period for which a Reliability Option is to be transferred, and the quantity of that reliability Option that is transferred.
- **Trading ahead of commissioning:** Do we allow Capacity Providers to sell on their Reliability Option before they have commissioned their plant?
- **Trading ex-post:** Do we allow secondary trading after the physical delivery of electricity?

3.5.2 The key I-SEM assessment criteria impacted by these choices are set out below:

- **Security of Supply:** Allowing providers to enter into secondary trading ahead of commissioning would enhance security of supply. A "failing" project now has the opportunity to find an alternative provider to accept its obligations to provide capacity, and hence avoid a future shortfall in capacity.

  For the impact of Security of Supply to be effective, the secondary trade would have to include all relevant obligations arising from the implementation agreement. This would mean that the third party would still be liable for penalties if it failed to deliver the capacity as required.

- **Competition and Efficiency:** Competition and efficiency are arguably enhanced by maximising the flexibility available through secondary trading. This would argue for:
  - Allowing trading before commissioning;
  - Allowing trading after delivery; and
  - Allowing the trading of custom products.

  On its own, the trading of custom products would reduce transparency – negatively impacting competition. This can be addressed by either:

  - Also including standard products – e.g to match standard maintenance outages; and
  - Deriving indicative (and suitably anonymised) price information for how the secondary value of Reliability Options varies with factors such as time of year, duration etc.

- **Adaptive:** Having only standard products trade would be very rigid, and difficult to adapt to changing market requirements.

3.5.3 In the light of these considerations, the SEM Committee seeks feedback from stakeholders on what limits should be placed on secondary trading timeframes, including:

- The timing of secondary trade execution- how soon after the auction should they be allowed, and how late in relation to real time delivery should they be allowed; and
- The length of Reliability Option which can be traded.

3.6 SECONDARY TRADING AND APPLICATION OF STOP-LOSS LIMITS

3.6.1 In Section 4.4, we consulted on the design of stop-loss limits. We stated that there will be annual "stop-loss" limits, and that we are consulting on whether to also have monthly and per event/per day "stop-loss" limits.

3.6.2 Another key issue is how to apply stop-loss limits, if and when a capacity provider transfers its Reliability Option for a period other than a complete "stop-loss" year. This issue is subject to ongoing consultation in the current DECC Consultation on reforms to the GB capacity market[29].

3.6.3 One simple option would be for the new acquirer to start from a zero position against the each "stop-loss" limit. This would simplify the secondary trading and registry process. It would also improve price transparency, since all secondary Reliability Options for a given capacity delivery period should have the same value / MW. If positions against stop-losses can be transferred with secondary trading, then a Reliability Option unit which is already close to its stop-loss level for the year is more valuable than an equivalent Reliability Option which has not yet hit its stop-loss limit.

3.6.4 If the new acquirer does not get credited with the original holder's loss accrual against the stop-loss limit, then there will be limited incentive on a Reliability Option holder near its stop-loss limit to manage its outages via Reliability Option secondary trading. This is not desirable, in that there is no plant that will be paid and incentivised to deliver at the time instead of the original Reliability Option holder when the original Reliability Option holder is on outage. However, if the loss accrual does transfer, the secondary acquirer of the Reliability Option would have limited incentive to perform anyway[30] due to the proximity to the stop-loss limit.

3.6.5 Another option is whereby the "stop loss" limit continues to follow the participant (see section 4.4). In this way the only thing that would change is the annual option fee revenue

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[29] See UK Department of Energy and Climate Change, CAPACITY MARKET: Consultation on reforms to the Capacity Market, 15D/457 15 October 2015

[30] as a result of owning the RO, in addition to energy market incentives which it would have anyway

received by the participants in the secondary trade. So the “stop loss” limit would continue to be the same multiple of the RO holders annual option fees, with the annual option fee revenue being altered by participants increasing or reducing their volume of ROs held.

3.6.6 We also recognise that:

- There may be equity arguments in favour of allowing a loss to transfer; and that
- Allowing a loss to transfer may have some marginal impact on the secondary value of Reliability Options, and that this could have a feedback effect on the value of primary Reliability Options, and hence the cost to customers of the capacity mechanism.

3.6.7 Therefore we seek feedback from stakeholders on whether a secondary acquirer of a Reliability Option should start from a zero position against each “stop-loss” limit, or whether the loss should transfer.

3.7 CONSULTATION QUESTIONS

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

A) Do respondents agree that direct secondary trading of Reliability Options should be permitted?

B) Should secondary trading of Reliability Options be via an organised secondary platform? If so, which one of the options is preferred?

C) Do respondents believe that “back-to-back” trading to lay-off exposure to difference payments should be permitted?

D) With respect to the creation of a centralised Reliability Option secondary market platform:

I. Is there likely to be sufficient demand for secondary trading to justify the cost of the development of a centrally organised platform;

II. Do respondents think that capacity providers should be allowed to acquire Reliability Option volume in excess of their de-rated capacity (plus the tolerance margin), and if yes, how the limit on Reliability Option volume for the net primary and secondary volume should be structured?

III. What limits should be placed on secondary trading timeframes, including: the timing of secondary trade execution - how soon after the auction should they be allowed, and how late in relation to real time delivery should they be allowed; and the length of the Reliability Option contract which can be traded?

IV. Should the Capacity Market Delivery Body maintain the processes and capability to undertake pre-qualification throughout the year, and what service standards are required for processing new applications?

V. Should a secondary acquirer of a Reliability Option start from a zero position against each “stop-loss” limit, or should the loss transfer?

Please provide a rationale for all of your responses.

4. DETAILED RELIABILITY OPTION DESIGN

4.1 INTRODUCTION

4.1.1 SEM 15-103 set out the SEM Committee's decisions relating to issues raised in the first of three consultation papers on the detailed design of the I-SEM Capacity Remuneration Mechanism (CRM) (SEM 15-044). This included a number of key decisions on the contractual mechanisms (Reliability Options) that will be used to determine payments to or by capacity providers, and how these arrangements give rise to payments to or by those providers. Specifically, Capacity Providers that hold Reliability Options:

- Receive option fees at the €/MW year price arising from the relevant auction. Participants located in Northern Ireland will receive these option fees in Pounds Sterling, based on the exchange rate at the time of the auction that gave rise to the Reliability Option.
- Make difference payments when the price at which they sell power exceeds the Market Reference Price specified in the Reliability Option.

4.1.2 A number of more detailed issues relating to the design of the contractual arrangements were left for consideration in this consultation paper. As discussed in the following paragraphs, these issues relate to:

- **Reliability Option Length:** It is envisaged that Reliability Options will be allocated to Capacity Providers through annual competitive auctions. This consultation paper considers the time period over which those Reliability Options should take effect, and whether this should differ between plant that, at the time of the auction either:
  - Is new plant that needs to be built;
  - Is existing plant that needs significant investment to maintain or enhance its ability to provide capacity; or
  - Is existing plant that can continue to provide capacity without the need for significant investment.
- **Stop Loss:** Decision 1 (SEM 15-103) agreed in principle to apply caps to uncovered Reliability Option difference payments. This consultation paper considers the design of these stop loss arrangements – specifically:
  - Whether we need stop loss limits for at the annual, monthly and daily level; and
  - The level at which those limits should be set.
- **Implementation Agreement:** Decision 1 (SEM 15-103) acknowledged where a Reliability Option is awarded based on plant that is yet to be built, there is a need to track progress with the build project, and administer financial penalties if the

build is delayed or abandoned. This consultation paper considers the detailed design of the agreement that could cover this build phase – including:

- The specification and measurement of the relevant milestones; and
- The level of exit penalties – and the performance bond required to cover those penalties.

4.2 RELIABILITY OPTION LENGTH

4.2.1 The introduction of Reliability Options under the I-SEM creates the opportunity to fix the price paid to some or all capacity providers for a year or for over periods longer than a year – by awarding the relevant provider a longer term Reliability Option.

4.2.2 Determining the optimal Reliability Option length for different capacity providers involves a trade-off between differing factors, these include:

- Financing risk: Single year Reliability Option may not offer sufficient revenue certainty to potential new entrants. Multi-year Reliability Option can provide this assurance allowing new investment in generation.
- Price risk: Risk around future capacity prices for consumers and investors can be hedged by awarding multi-year Reliability Option. However these multi-year Reliability Options lock in today's price and may not deliver good value for money for consumers. Single year or shorter term Reliability Options may provide more efficient entry and exit signals.
- Volume risk: Multi-year Reliability Options lock consumers into buying a particular volume of generation capacity. This places the risk of over procuring on consumers.

4.2.3 When compared with an annual capacity price fix, a longer time price fix would lead to [31]:

- **Reduced Financing Cost**: Reduce the financing risk for the relevant capacity. To the extent this leads to a lower cost of capital for the capacity developer, this should (through competition) lead to lower costs to the consumer;
- **Risk of Stranding:** Increase the risk that consumers commit to buy capacity that in later years is not needed (e.g. because cheaper capacity is now available). This risk is most extreme if existing plant is able to benefit from long-term Reliability Options, but could also occur if the Reliability Options awarded to new plant are excessively long.

4.2.4 There are potentially significant benefits in awarding longer term Reliability Options to new-build plant, whilst awarding annual Reliability Options to existing plant. This is explicitly mentioned in the DG Competition's working papers considering how Capacity

[31] These effects are discussed in greater detail in Appendix C of the GB Capacity Market Impact Assessment, September 2014.

Remuneration Mechanisms can be designed to be compliant with State Aid Guidelines. Notably, this states:[32]

> *"Depending on the financing arrangements for new power plants in a Member State, the contract lengths available may have a significant impact on the extent to which new projects can compete with existing projects. A longer contract provides additional certainty which can reduce the cost of financing a new project by allowing the investor to spread any debt service costs over the life of the contract. This could reduce the capacity price required per year, and help ensure a new project is competitive against existing projects in the market. This can help ensure the measure overall is proportionate, since if in years when new entry is required all existing capacity is also paid a high price, this could lead to windfalls for existing capacity . The potential for new entry at a competitive price may also be critical for controlling the market power of existing capacity providers."*

4.2.5 This benefit has also been recognised for the procurement of Systems Services[33] - where it is proposed that new build service providers should be able to fix the price they receive for those services for up to 15 years. There are various levers available to manage and influence the balance between these conflicting effects, notably:

- Only awarding Reliability Options longer than a year where significant up-front investment is required to deliver that capacity (i.e. for new and upgraded plant). Once those initial (longer term) Reliability Options expire, the relevant plant becomes an "existing" plant that competes for one-year Reliability options;
- Setting the maximum Reliability Option lengths consistent with balancing the potential for reduced financing cost with the risk of stranding and inefficient entry/exit signals.

4.2.6 Both of these levers have been used in the GB Capacity Market as well as in US Capacity Markets; however, the length of contract available for new plant varies :

- GB allows new capacity to elect how many years of contract it requires – up to a maximum of 15 years - whilst existing plant get annual contracts and plant upgrades can elect for contract lengths of up to 3 year contracts;
- ISO NE allows new capacity to elect the how many years of contract it requires – up to a maximum of 7 years (recently increased from 5 years)
- PJM allows new capacity to elect how many years of contract it requires – up to a maximum of 3 years.

[32] "Designing a Competitive Bidding Process, and Ensuring Competition Between New and Existing Capacity", European Commission. April 2015
[33] These are being procured through DS3.

4.2.7 In each of the above cases, the investor in the new plant can choose revenue certainty after the first year of the contract, but in doing so it forgoes the potential for higher revenue in future years – should the auctions for those years result in a higher price.

4.2.8 The following paragraphs consider each of the following

- The merits of awarding longer term Reliability Options to new and refurbished plant;
- How we would distinguish between new plant, existing plant and upgraded plant;
- The appropriate length of Reliability Options; and

Awarding longer term contracts for capacity requiring investment

4.2.9 As discussed above, International experience suggests a benefit in awarding multi-year Reliability Options for new plant, whilst existing plant should only be eligible for annual Reliability Options. The following paragraphs consider the merits of this approach by reference to three broad options:

- **Option 1 (Same Length):** All Reliability Options are the same length. This has two sub-options:
  - **Option 1a (Short):** All Reliability Options are for 1 year. New build and upgraded plant needs to sell its capacity on an annual basis to recover any "missing money"
  - **Option 1b (Long):** All Reliability Options are for multiple years, with start dates staggered such that some Reliability Options are up for renewal each year (see Figure 10)
- **Option 2 (Different Length):** The Reliability Options length varies with the level of required capital investment – with different Reliability Options lengths for existing plant, upgrades to existing plant and for new plant.

4.2.10 The following summarises an assessment of these options against the I-SEM assessment criteria:

- **Internal Electricity Market (Long for New Entrants):** DG Competition's discussion of Capacity Remuneration Mechanisms mentions the benefits of having long-term Reliability Options only for new build capacity. This is the approach which has been adopted in GB, so is consistent with the I-SEM's immediate neighbour.
- **Competition (Long for new-entrants):** DG Competition has already identified that allowing longer-term Reliability Options for new-entrants can significantly enhance competition between new and existing plant for the provision of capacity. This argues strongly for Option 2.
- **Efficiency:** Option 2 (different length) is best for efficiency.

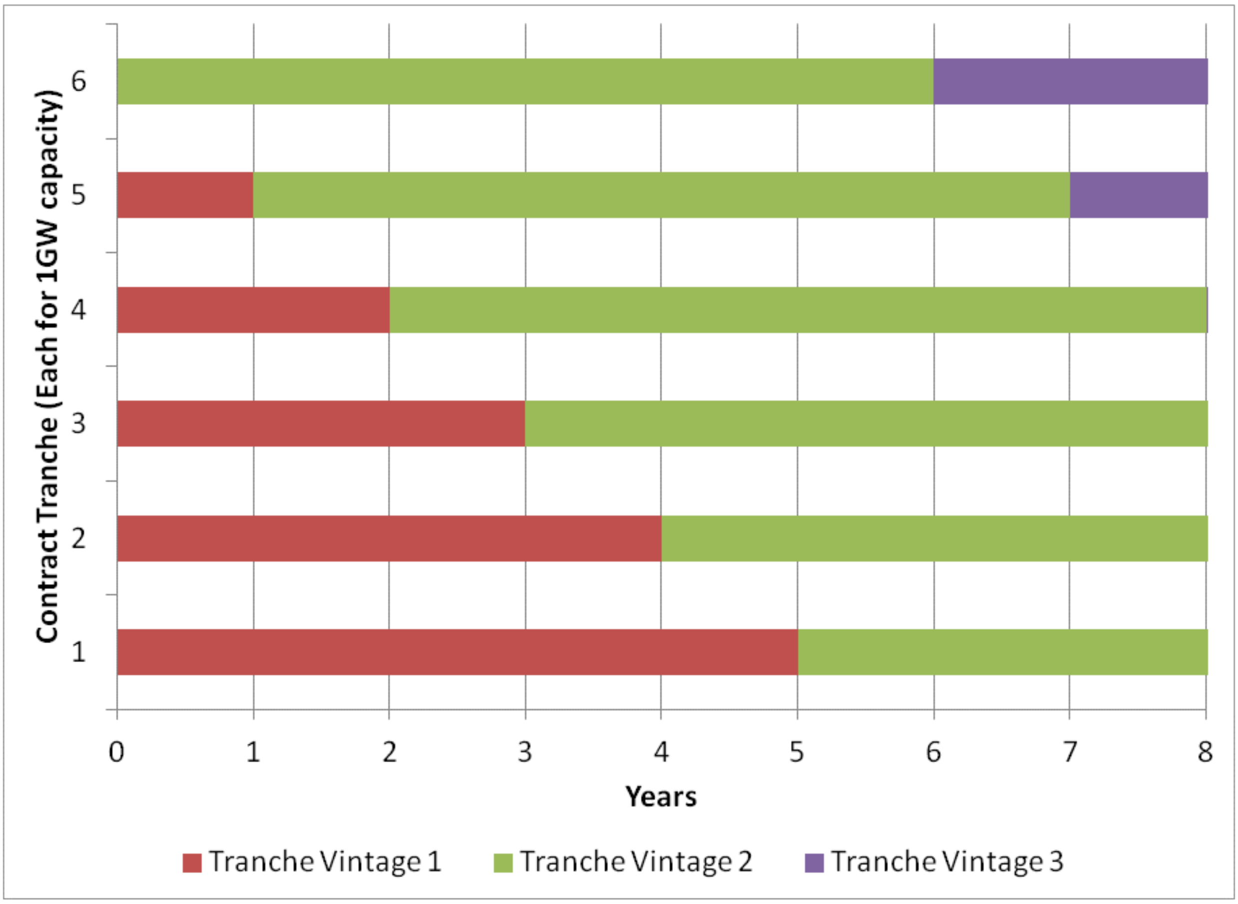
- This reduces the risk (in terms of future cash flow certainty) to those investing in new or enhanced capacity – by awarding such providers a longer term Reliability Option;
- The award of short Reliability Options to existing capacity does not act as a barrier to efficient exit of old capacity, when more cost effective capacity is available, however,
- Long-term Reliability Options can reduce overall efficiency by locking in investments that may turn out to be inefficient at a point in the future.

- **Environmental (Avoid all long):** Option 1b acts as a barrier to exit for existing capacity. This would prevent the entry of more efficient capacity with a lower environmental impact.
- **Equity:** Option 2 **(different length):** will result in different treatment for new and existing plant that backs Reliability Options.
- **Stability (Long for new-entrants):** The State Aid Guidelines envisage that the auction price for capacity will tend to zero when there is a surplus of that capacity. This would imply that prices would only go "high" in annual auctions where new capacity is required. This would not give a stable revenue consistent with lowering the cost of capital for new entrants, and is likely to create difficulties in maintaining the stability of end-user tariffs.
- **Security of Supply (Long for new entrants):** At some point, new build capacity will be required to maintain security of supply. That new-build capacity is more likely to be realised if investors are able to reduce the risk (and hence cost) of the project by securing the level of their capacity revenue for a number of years.
- **Adaptive:** Any longer term Reliability Options will have to be honoured for their duration, reducing the adaptability of the I-SEM. The extent of this impact depends on how much of the capacity requirement is covered through long term Reliability Options. Option 1a (all short) would be the most adaptable, with option 1b (al long) being the least adaptable.

4.2.11 The following assessment criteria do not significantly impact the choice between these options:

- **Practicality and Cost:** The Reliability Option length does not impact the practicality or cost implementing the I-SEM

Figure 10: Six yearly rolling procurement of 6GW of capacity



Identifying new and upgraded plant

4.2.12 If it is decided the Reliability Option lengths available to bidders should vary by whether they are backed by new plant, upgraded (or refurbished) plant or existing plant, we need to consider how we identify which plant is new or existing.

4.2.13 There are number of ways that can be envisaged to determine whether plant is new or refurbished, including:

- **Option 1: Cost Threshold:** Any project with a spend per MW above a pre-specified threshold is considered to be new-build, with a similar (but lower) threshold for refurbished plant. This is the approach used in the GB capacity market, where
  - the “new build” threshold is based on the low range of estimates for the per MW cost of building new capacity (in this case a new Open Cycle Gas Turbine)
  - the “upgrade” threshold is based on the low range of estimates of the per MW cost of life extension for the existing generation fleet.

- **Option 2: Tangible Facts:** The decision over whether a specific capacity provider is classified as a new-build, upgrade or existing plant is based on observable facts relating to that provider. Such tangible facts could be:
  - Whether the capacity is being provided from a site that has previously provided capacity;
  - Whether the capacity is being provided across a new connection; and
  - For capacity from an existing site, whether the capacity now offered is an increase over that offered previously.
- **Option 3: Expert Judgement:** The "expert judgement" approach adds to the "tangible facts" approach to provide a judgement on whether capacity is actually new, existing or an upgrade. In addition to the tangible facts, this would include a review of the actual investment in the plant providing the capacity

4.2.14 In practice the, difference between these options relates to the "practicality and cost" criteria, with all other criteria being indifferent on the choice of option. Notably:

- These decisions will be made by an agent (the TSOs) on behalf of the market. It is therefore beneficial for decisions to be as objective and transparent as possible. This argues against option 3, which has a large element of judgement;
- Option 2 is transparent and objective; however, it may be difficult to define the complete set of "tangible facts" that would correctly discriminate between an existing plant, an upgrade and a new plant;
- Option 1 has the attraction of simplicity and transparency; however, it may be difficult to identify thresholds that:
  - are not set too high such that they rule out actual new-build or upgrade projects; or
  - Are set too low such it is relatively easy for existing plant to be classified as new or upgrade – even though the relevant investment does little to enhance the life or capability of the plant.

How long should specific Reliability Options for new and refurbished plant be?

4.2.15 Once we have decided whether all Reliability Options should have the same duration, we also need to consider the specific length of each Reliability Options in years. This is mainly an issue for new and refurbished plant – assuming that existing plant will get Reliability Options of one year.

4.2.16 There are two key elements to consider in setting the specific lengths of these Reliability Options:

- Should these Reliability Options lengths match those proposed for DS3; and
- How should the Reliability Options length relate to the economic life of typical investments.

4.2.17 For the first of these there are clear benefits in matching the length of Reliability Options awarded for capacity with those for the provision of DS3 services (currently envisaged to be up to 15 years). The main benefit of offering “long” Reliability Options to capacity requiring investment relates to reducing the risk of financing that investment, and hence the cost of that finance. In most (if not all) cases, the physical plant that provides capacity will also provide some or all of the DS3 services.

4.2.18 In setting the actual length of Reliability Options there is a trade off between two factors:

- The benefits of lower financing costs for new investments; and
- The costs of stranded investments. This occurs when within the plant’s revenue from its Reliability Options allows it to continue operating when it should have exited the market (e.g. because of improvements in plant efficiency, or changes in the pattern of demand)

4.2.19 The trade off between the above two factors are commonly considered as driving the economic life for plant. GB Government recently considered the economic life of CCGT plant in setting the maximum contract length available through its capacity mechanism[34], identifying a 15 year economic life. This tallies with recent experience in reviewing business cases for investment in new thermal power plant across Europe, where economic life beyond 15 years is challenged by:

- Projected ongoing improvements in the thermal efficiency of new-build power stations;
- The decline in the thermal efficiency of most thermal power stations across their lives;
- Erosion of the market available to any thermal plant over time by factors such as:
    - The increased deployment of low-carbon generation; and
    - Energy efficiency measures and their impact on the profile of demand over time.

4.2.20 In addition to the recent experience of thermal power station business cases, the GB analysis highlights the benefits (in terms of lower financing costs) of allowing contracts to extend to 15 (rather than 10) years. The lower risk nature of the SEM would impact the extent to which these arguments apply in Ireland, the I-SEM energy market is arguably more similar to that in GB. An extract from the GB Impact Assessment is set out below.

> *“Under current UK energy market conditions, project finance lenders are unlikely to take any merchant risk, meaning that the revenues supporting debt service must be supported by an agreement. Contract lengths of 10 years are too short to optimise the debt and would lead to a higher price in either amortising debt (repaying the total loan together with interest payments) over the shorter period*

[34] See Appendix C of the GB Capacity Market Impact Assessment, September 2014.

or, in reducing gearing levels (the proportion of the loan to the total cost), requiring a greater proportion of equity funding (i.e. via shareholders) at higher hurdle rates, thereby raising the overall cost of finance.

We assume that increasing the maximum contract length for new build capacity from 10 years to 15 years will significantly reduce financing risk. This is because commercial debt tenors are currently circa 7 to 8 years. Therefore, a 15-year contract length will allow refinancing mid-term (at, for example, year 7). Lenders for the initial 7-year debt term are able to size the debt as if it were over a 13 or 14-year term, since they will be able to assume the debt can be refinanced in the middle of the capacity agreement term and can also structure repayments assuming that a proportion of the debt can be refinanced. Debt service payments will therefore be lower (reflecting debt being effectively amortised over the longer period), reducing the costs to investors."

4.2.21 Conversations with potential developers of power plant in the I-SEM indicate that:

- A Reliability Option length of 15 years (similar to that proposed for DS3) is likely to be sufficient for them to finance their projects at a reasonable costs; and
- That at least some of those developers would expect their plant to continue to be economic for many years beyond the end of that initial Reliability Option. They believe that, following the end of their fixed term Reliability Option, the revenues they will obtain from annual Reliability Option auctions will be sufficient. This is consistent with the time value of money – meaning that the present value of cash flows (and hence the extent they contribute to initial investment costs) decline with time. For example, for a real discount rate of 9%, the value of €1 in year zero declines as follows:
    - €0.92 in year 1;
    - €0.65 in year 5;
    - €0.42 in year 10; and
    - €0.27 in year 15.

4.2.22 We have considered the following generic frameworks for how the maximum Reliability Options length is established for new (and refurbished plant)

- **Generic Economic Life (e.g. 15 years):** This option is similar to that adopted in the GB Capacity Mechanism. All new build plant would be able to avail of Reliability Options with a length of up to that generic economic life;
- **"Balanced" economic life (e.g. 10 years):** This option would recognise that developers are prepared to accept they will need to rely on annual reliability options for the latter years of their economic (and technical) lives.
- **Shortest Economic Life (e.g. 5 years):** This option would set the maximum Reliability Options length based on the shortest economic or technical life of

technology that is capable of providing capacity. This could deliver a maximum Reliability Option length similar to those observed in US Capacity Markets.

- **Technology Specific Life:** This option would set different maximum Reliability Option lengths for new entrant plant based on the estimated economic life for its technology type. This would allow more detailed control over the risk of future stranded costs.
- **Technology Specific Balanced:** This option would set different maximum Reliability Options lengths for new entrant plant to a length just shorter (e.g. 66%) of the estimated economic life for its technology type. This would allow more detailed control over the risk of future stranded costs, as well as limiting the impact on competition on future capacity auctions.

4.2.23 The following summarises an assessment of these options against the I-SEM assessment criteria:

- **Internal Electricity Market:** The European Commission has indicated a general support for the award of longer term Reliability Options to new-build plant; however, it has also acknowledged that longer-term Reliability Options have disadvantages in terms of both the risk of future stranded costs, and in reducing competition in future capacity auctions. This suggests setting the maximum Reliability Options length somewhat shorter than the economic life of expected plant – as in the “Balanced” and “Technology Specific Balanced” options above. The balanced options would, however, lead to a different approach to that adopted in the (GB) electricity market neighbouring the I-SEM – which has adopted a 15 year contract length but would be closer to ISO New England contract durations.
- **Security of Supply:** Security of Supply is arguably enhanced by ensuring the costs of generation entry are low at times when the I-SEM needs new capacity. This would argue for a maximum Reliability Option length that matches the economic life of plant – suggesting either the “Technology Specific Life” or “Generic Economic Life” approaches
- **Competition:** As noted by the European Commission, changes to the maximum length of Reliability Option available to new entrants have both positive and negative impacts on competition. Longer Reliability Options will reduce the capacity price of new entrants, lowering the auction price; however, they also increase the risk of future stranded costs and reduce competition in subsequent auctions. This represents a transfer of risk from investors to customers – with any increase in competition in the short term being offset by less competition in the longer term. This suggests setting the maximum Reliability Options length should be somewhat shorter than the economic life of expected plant – as in the “Balanced” or “Technology Specific Balanced” options above.
- **Adaptive:** The market as a whole will have to honour the commercial effect of a Reliability Option for its full term. This could complicate future changes to the wholesale trading arrangements (a point noted by the European Commission).

This would argue for the options with shorter maximum Reliability Options lengths as more adaptive than longer lengths.

- **Stability:** Clearly, a longer Reliability Option length will lead to more stability in prices obtained by new capacity providers, and in those prices paid by Suppliers.
- **Efficiency:** As with other criteria, efficiency argues for a balanced approach – acknowledging both positive (from lower cost of capital) and negative (from stranded cost risk, and potential reduced competition) impacts of increased Reliability Option length.
- **Practicality and Cost:** Each of the above options assumes it is possible to assess the economic life of capacity providers. In practice, this is non trivial – depending on a number of assumptions relating to the costs of that technology, as well as assumptions for how electricity demand, and other capacity provider technologies will evolve.

In practice, the market assumption for the economic life of plant that is commonly built (e.g. CCGT) can be observed from the financing terms of, and (energy and capacity) prices offered by those plant. This information can be used to sense check any modelling of economic life. This would argue against the "technology specific" options as:

- The technology specific options will increase the costs of administering the allocation of Reliability Options to capacity providers, and
- The determination of economic life will be more accurate for some technologies (those which are frequently deployed) than for others.

4.3 OPTION FEE INDEXATION

4.3.1 It is anticipated that the bulk of capacity will be procured a number of years ahead of when it will be contracted to be available. This lead time is required to allow new capacity (which will take time to build) to compete on an effective basis with existing capacity.

4.3.2 Given there is a lag between the time of a capacity auction, and the time when capacity is delivered, there are potential benefits in indexing the price (option fee) that arises from the auction. This benefit arises if the costs that a typical bidder will cover using the option fee are themselves subject to inflation, and matching the indexation of the option fee to that inflation.

4.3.3 It is expected that when parties bid into auctions to be awarded Reliability Options, competition will drive them to bid their expectation of any "missing money". Providing the parties behave rationally, they should at least recover their variable costs from the energy market, meaning this "missing money" relates to some or all of their fixed costs. These costs are varied, with significant components including:

- The cost of re-paying the finance for the initial construction of the capacity;
- Fixed staffing costs for the capacity;

- Connection costs; and
- Local taxation (e.g. business rates).

4.3.4 The latter three of the above cost components would typically increase in nominal terms over time. It is also possible for the first component (financing costs) to increase with inflation – for example with the use of index linked debt. This form of debt is becoming relatively common. In simple terms, index linked debt works as follows:

- Any outstanding amount of the loan is increased by inflation on a periodic (e.g. annual) basis;
- Interest is charged at a real (as opposed to nominal) basis.

4.3.5 The above argues that efficiency will be improved if the Reliability Option Fee is increased in line with an inflation index.

4.4 STOP-LOSS LIMITS

4.4.1 The "stop-loss" limit is a limit on a capacity provider's exposure to RO difference payments. The objective of a stop-loss limit is to limit risk to capacity providers and make the market more investible. If a low "stop-loss" limit is set, capacity provider's risk is capped at a low level, which should reduce its risk and cost of capital. However, a lower "stop-loss" limit also potentially:

- Limits the incentive on capacity providers to make capacity available at time of system stress; and
- Increases the size of the "hole in the hedge" and increases the level of RO difference payments that need to be socialised.

4.4.2 In SEM-15-103 the SEM Committee stated that:

- It is appropriate to apply caps to uncovered Reliability Option difference payments[35].
- The "stop-loss" limit should apply to annual losses, and may be applied to monthly and per event /per day losses;
- The annual "stop-loss" limit should be set as a multiple of capacity fees and should be set in the range x1 to x2 annual capacity fees.

4.4.3 The SEMC is of the view that "stop-loss" limit should be applied to "uncovered" difference payments because this approach:

[35] Where a capacity provider has received an energy payment by selling its capacity into the energy market, its Reliability Option difference payment is covered by energy market revenues, and it suffers no loss, it merely has its scarcity rent capped. The Reliability Option difference payment it makes on this occasion should not count towards the "stop-loss" limit. However, if the generator's capacity is unavailable, and as a result it has to pay out a difference payment without having an offsetting energy revenue, its RO difference payments are *uncovered* and it suffers a genuine loss. This Reliability Option difference payment should count towards the "stop-loss" limit

- Better reflects the risk placed on capacity providers- where capacity providers sell energy into a market with scarcity pricing, they have an income to offset the risk of accumulating Reliability Option difference payments;
- Maximises the extent to which scarcity rents are taken back from generators, one of the features which underpinned the choice of Reliability Options in the I-SEM CRM HLD; and
- Provides a better hedge to Suppliers, and minimises the size of any Reliability Option difference payment shortfall that needs to be socialised- another of the features which underpinned the choice of Reliability Options in the I-SEM CRM HLD.

4.4.4 These limits are expected to apply equally to all technologies. In the case of intermittent technologies such as wind/solar, the "stop-loss" limit will also serve to limit the exposure of the generator to making difference payments at times of system stress when they are unable to generate due to factors beyond their control (i.e. because the wind is not blowing or the sun is not shining).

4.4.5 Without a "stop-loss" limit participants may manage this risk through bids into the capacity auction, which may:

- Lead to bidders introducing the risk in their bids increasing the clearing price;
- Lead to some plants not participating (premature exit signal).

4.4.6 In SEM-15-103, the SEM Committee stated that it will consult further on the level and structure of the cap on Reliability Option difference payments. Further work is required to:

- Determine the structure of other "stop-loss" limits (i.e. whether to also apply monthly and per event/ per day "stop-loss" limits); and
- Determine the level of these "stop-loss" limits.

4.4.7 We discuss each of these points in turn below.

Structure of stop-loss limits

4.4.8 In SEM-15-103, the SEM Committee stated that it would set an annual "stop-loss" limit, and was also minded to set other "stop-loss" limits. These could include:

- A monthly stop-loss limit; and/or
- A per day (or event) stop-loss limit.

4.4.9 The rationale for monthly and/or per day stop-loss limits are to prevent a single event or series of events in a concentrated period (which might have a common cause, such as a cold spell of a week or two) removing the Reliability Option difference payment incentive for the remainder of the year.

4.4.10 Additionally, we need to define:

- The annual period to which annual stop-loss limit would apply. The current Capacity Payment Mechanism works on calendar year basis- at least for the determination of the Annual Capacity Payment Sum and for payment profiling. However, for the purpose of defining annual stop-loss limits it may make sense to have the entire Winter period within one "stop-loss" year, and would favour moving to defining the "stop-loss" years as the period from 1 October to 30 September;
- The monthly stop-loss period. We would propose to define this on a Calendar month basis;
- The definition of an event, for stop-loss purposes. We would propose to define this as any Settlement Day; however, alternative definitions are possible including:
    - Any contiguous set of settlement periods in which Administered scarcity applies, i.e. there is insufficient capacity to meet the target operating reserve. Alternatives (not mutually exclusive) would be to define it:
    - Any contiguous set of settlement periods in which the Market Reference Price exceeds the Reliability Option Strike Price. A weakness of this approach is that with the Split Market Reference Price, this would be triggered if any of the market reference prices were in excess of the Reliability Option Strike price- e.g. having an event prolonged by a vertical integrated player doing a small volume, high price intra-day trade between its Generation and Supply arms.
    - As a single event, if there was scarcity on consecutive days. For instance, it might be that a single cause (e.g. a major outage) caused scarcity during the day-time peak on consecutive days, but scarcity was not declared during the intervening night.

4.4.11 We note that in GB, the introduction of a per event limit has resulted in significant additional work to define what constitutes an event.

4.4.12 We welcome feedback on all these points.

Level of Stop-Loss Limits

4.4.13 In SEM-15-103, the SEM Committee stated that it is minded to set an annual "stop-loss" in the range of between x1 and x2 annual capacity fees.

4.4.14 The SEM Committee welcomes feedback on the following points:

- Whether it is appropriate to define the "stop-loss" limits in terms of a multiple of annual fees;
- Where in the range x1 to x2 of annual capacity fees, the annual stop-loss limits should be set at;
- What level the monthly stop-loss limit should be set at (if there is one); and
- What level the per event stop-loss limit should be set at (if there is one);

4.4.15 When setting the "stop-loss" limits, the SEM Committee recognises that an appropriate balance needs to be struck between:

- Incentivising capacity providers to perform under all circumstances (for system security reasons), which would favour uncapped Reliability Option difference payments for capacity providers;
- Minimising any shortfall in Reliability Option difference payments, which would also favour uncapped Reliability Option difference payments;
- Minimising disincentives to sell power in the DAM, if the risk of Reliability Option difference payments is capped, the risk of having to buy back forced outages in the IDM or BM is not. This disincentive effect is also minimised if Reliability Option difference payments are uncapped; and
- Not exposing capacity providers to excessive risk. Excess risk may either be priced into auction offers (which would add to customer bills) and/or deter investment (which would threaten system security).

4.5 COMMISSIONING WINDOW

4.5.1 The Commissioning Window is the time from the date of the Capacity Auction until the point at which a Reliability Option will be terminated for failure to achieve Substantial Completion.

4.5.2 The Commissioning Window is divided into two parts:

- The period from the Auction Date until the start of the first Delivery Year under the Reliability Option; and
- An additional period up to the **Long Stop Date** to give a project time to commission. This allows projects with longer construction times to participate in the capacity market. It also reduces the risk for project sponsors as a delayed project will still be able to access option fees for the vast majority of the length of its Reliability Option.

4.5.3 The time until the start of the first Delivery Year needs to be sufficient to enable Substantial Completion to be achieved in most cases.

4.5.4 There are a number of reference cases that can be considered in deciding the length of the Commissioning Window. Notably:

- The new Capacity Markets in both Great Britain and Italy allow a period of four years from the Auction Date until the start of Delivery under Capacity Contracts.
- Eurelectric in its 'Reference Report for European Capacity Markets' (March 2015) suggests a period of 3-4 years from Auction to capacity delivery is sufficient.
- It is assumed that where new capacity requires both a Reliability Options and a DS3 Contract to proceed, the Commissioning Window will need to be consistent between the two agreements. The DS3 Decision Paper of December 2014 sets a

maximum of five years for the length of the Commissioning Window for new DS3 capacity.

4.5.5 In determining the timeline for procuring capacity there are a number of issues to consider, these include:

- **Efficient capacity allocation:** The further out an auction for capacity is from the delivery year the greater the uncertainty is about the capacity assessment. This uncertainty regarding the volume to procure comes from both supply and demand. Procuring capacity for a T-1 auction would carry less risk (in terms of procuring the correct volume of capacity) than for a T-4 auction.

- **Competition in auction:** Having an auction held a sufficient period in advance would allow new build compete against existing plant, this would ensure existing economic plant would not offer capacity above the cost of new entry. Also having the auction for example at T-4 would allow new build plant obtain a capacity price before committing to build.

- **Technology neutrality:** The choice of how far out the auction is held could affect the mix of plant which comes forward to compete in the auction. A shorter period such as T-1 could favour existing and DSU plants, while a longer period such as T-4 could favour a new CCGT or storage plant while disadvantage DSU units.

4.5.6 The lead time chosen between the capacity auction and the first delivery year has a large bearing on the competitiveness of different plants and technologies in the capacity auction. Storage or other technologies may require longer lead times in order to be able to participate in the capacity mechanism.

4.5.7 While other technologies such as DSUs require a shorter lead time between the auction and delivery period. One possible solution to accommodate differing technologies such as these is to run a supplementary capacity auction closer to the delivery period (e.g. D-1). This would be in addition to the primary auction held further out from the initial delivery year (e.g. D-4).

4.5.8 A period between the Auction Date and the start of delivery under the Reliability Option of **four years for new capacity is proposed.**

4.5.9 The Long Stop Date defines a window after the start of the first delivery year during which the Substantial Completion milestone can be achieved. Failure to achieve Substantial Completion by the Long Stop Date would trigger termination of the Reliability Option.

4.5.10 In the new GB capacity market, new capacity is given a window of 12 months after the start of the first delivery year to achieve the equivalent of Substantial Completion. Substantial Completion requires the unit to be Operational (broadly as defined in the Grid Code) and for its physical generating capability, as de-rated, to have achieved at least 90% of its contracted capacity.

4.5.11 Following failure to achieve the Long Stop Date, new capacity is given a further 120 days to become Operational and for its physical generating capability (as de-rated) to have achieved at least 50% of its contracted capacity.

4.5.12 An argument could be made that later delivery of capacity contracted through a Reliability Option has a more serious impact on the I-SEM than on GB given the smaller size of the market and the larger proportion of the capacity requirement represented by an individual plant. This might suggest that the values in GB should be considered as an upper bound on those to be used in the I-SEM.

4.5.13 In GB, the Long Stop Date is extended in line with any delay in completion of the transmission or distribution connection where this moves beyond the date set out in the relevant Connection Agreement.

4.5.14 It seems reasonable that delays to the Substantial Completion of a project solely caused by the Transmission or Distribution Connection being delivered later than contracted should permit extension of the Long Stop Date in the I-SEM.

4.5.15 In a power station EPC contract, late delivery attracts Delay Liquidated Damages. These will typically be limited to 10-20% of the contract value. Once Delay LDs are exhausted, the purchaser will typically have the right to terminate the contract. A potential application of this principle to Reliability Options would say that:

- The total contract value is the value of option fees over the life of the Reliability Option;
- The equivalent impact to "Delay Liquidated Damages" is achieved through the loss of option fees by the developer whilst the plant is being completed; and
- For [15 year] Reliability Options (equivalent to the length of GB Capacity Contracts) this implies a Long Stop Date between 18 months and 3 years after the start of the first Delivery Year.

4.5.16 Alternatively, the direct cost to the system of operating the I-SEM with reduced contracted capacity could be modelled as proposed in the discussion on the level of the performance bond in 4.6.39. This cost could then be used as the analogue of Delay LDs and used as the basis for setting the Long Stop Date.

4.5.17 If a Reliability Option is to be terminated for failure to deliver the contracted capacity, or at some lower level, by the Long Stop Date then the I-SEM will need to procure this capacity in a subsequent Capacity Auction. As a result, the timing of the Long Stop Date should be consistent with the timeframe required to re-tender for the missing capacity in the next scheduled Capacity Auction.

4.5.18 Where new capacity has also been contracted to provide system services under a DS3 contract, termination of the Reliability Option is likely to compromise the financial viability of the capacity and may lead to a termination event under the DS3 contract. Termination under the DS3 contract may also lead to termination of the Reliability Option.

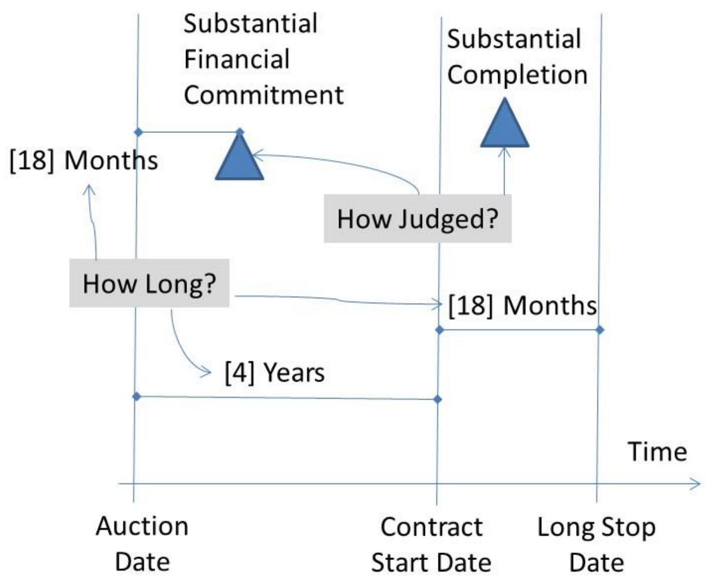
As a result, it is important that the Long Stop Date should be consistent across the Capacity and DS3 Contracts.

4.5.19 The DS3 Decision Paper from December 2014 does consider the need to provide further time after the closing of the Commissioning Window to achieve a minimum level of capability. The minimum threshold capacity for a Reliability Option to become effective may need to be consistent with the minimum DS3 capability (where relevant) to prevent one set of obligations becoming effective while the other is terminated.

4.5.20 In choosing the two components that make up the Commissioning Window there is inevitably a trade-off between the 'competition' and 'stability' assessment criteria for the sponsor with the 'security of supply' and 'efficiency' criteria for the market.

- **Competition**: the longer projects are given to reach Substantial Completion the greater the potential range of new capacity projects that could be brought forward.
- **Stability**: if the time periods chosen are too short, it increases the delivery risk for projects which will potentially increase bids and reduce competition.
- **Security of supply** and **Efficiency**: if the Commissioning Window is too long, it will be harder to maintain the agreed security standard for the system as forecasting both demand and the availability of existing capacity becomes more challenging the further into the future a view is taken. It will also increase potential costs to the market for late delivery or failure of projects. However, as noted above an unrealistically brief Commissioning Window could also be a threat to efficiency and security.

Figure 11: The Commissioning Window



4.6 IMPLEMENTATION AGREEMENT

Introduction

4.6.1 The SEM Committee has decided that Implementation Agreements are required. These Implementation Agreements will be based around a number of defined milestones. These milestones shall include:

- Substantial Financial Commitment
- Commencement of Construction
- Substantial Completion
- A number of additional project milestones to be defined by the bidder

4.6.2 The first CRM Decision document identified a number of elements of the detailed design of implementation agreements to be considered as part of the CRM Consultation 2. These include:

- The number, duration and measurement of milestones;
- The consequence of failing to meet a milestone;
- The size of a security bond; and
- The extent to which this approach can and should be aligned with that for DS3.

4.6.3 This section will start by discussing the milestones against which new capacity projects can be monitored and will then consider the reporting requirements against these milestones. It will then move on to look at potential termination conditions. Finally, it will conclude with a discussion of the level of the Performance Bond and how this should change over the course of the Commissioning Window.

Milestones

4.6.4 Clear milestones are needed as the basis for progress reporting and potentially as times when the level of the Performance Bond should change. Failure to achieve some milestones may also be used as a condition for termination of a Reliability Option.

4.6.5 The First CRM Decision Document requires the establishment of the following milestones: Substantial Financial Commitment, Commencement of Construction and Substantial Completion and a number of additional project milestones.

4.6.6 **Substantial Financial Commitment** is broadly cognate with the concept of Financial Close for a project. This would normally require that all the Major Contracts and financing are in place, though some (or all) of these may have been signed with Conditions Precedent still outstanding, e.g. still awaiting final planning consent.

4.6.7 In GB, the analogue of Substantial Financial Commitment must be achieved within 18 months of the Capacity Auction (although there is a current consultation[36] to reduce this to 16 months but this is purely to improve integration with the auction timetable). For this milestone, GB require that either:

- 10% of the total project spend has been paid out; or
- At least one Major Contract has been signed and all financing is in place and there is a Board resolution committing to delivering the capacity as contracted. A "Major Contract" is an agreement(s) covering the supply of major components which in total amount to at least 20% of the total project spend.

4.6.8 Discussions with some project developers within the I-SEM have suggested that 9-12 months may be sufficient to achieve Substantial Financial Commitment.

4.6.9 The GB definition of the Substantial Financial Commitment milestone seems sufficient for the I-SEM. A maximum period of 18 months would seem to be appropriate for the time between the Auction Date and this milestone.

The same milestone would be relevant to DS3 contracts.

4.6.10 **Commencement of Construction**: while this is conceptually easy to understand, it will be more difficult to define in the Implementation Agreement. The rules for the capacity market in GB use this milestone, but fail to define its meaning in detail. It could be linked to something within the EPC[37] Contract or an analogous contract, e.g. one for civil works. As in GB, it seems sensible to link it to the project schedule submitted as part of the qualification process. One approach to tightening the definition of this milestone would be to link it to a minimum level of spend or specific tasks (or types of task) that should be associated with Commencement of Construction.

4.6.11 **Substantial Completion**: would mean that the new capacity is operational and has demonstrated the ability to deliver (after de-rating) a significant proportion of its Reliability Option capacity. It is anticipated that a definition of Substantial Competition similar to that used for GB would be appropriate for the I-SEM. Notably;

- In GB, "operational" is defined in terms of the Grid Code for transmission-connected capacity and requires an independent expert to certify that a distribution connected unit has passed all the necessary commissioning tests and is permitted to export onto the distribution network.
- To achieve Substantial Completion in GB, new capacity must be capable of producing 90% of its Reliability Option capacity, after de-rating.
- The definition of Substantial Completion used in GB is consistent with the Implementation Agreements previously used in Ireland when contracting for new

[36] Capacity Market: Consultation on Reforms to the Capacity Market, 15D/457 (DECC, 5 Oct 2015)
[37] Engineering, Procurement Construction and Commissioning

capacity in 2003, i.e. that the capacity is operational and has met a certain performance standard.

4.6.12 **Additional Milestones**: There is a potential need for additional milestones between the Auction Date and first delivery of capacity. This need is being consulted on in GB, following a major CCGT project not meeting its Substantial Financial Commitment milestone, leading to a projected shortage of capacity in the GB system. This event has highlighted the need for more milestones such that:

- "Failing" projects can be identified earlier; and
- Replacement capacity procured to manage any impact on Security of Supply?
- With only three milestones, there is only limited information available to the RAs and TSOs on the progress of new capacity projects and the risk that new capacity may terminate its Reliability Option early, will deliver late or will fail to deliver even a minimum level of capacity within the Commissioning Window. The additional milestones need to be spread across the period of delivery uncertainty, rather than bunched together close to Substantial Completion.

4.6.13 GB is proposing seven additional milestones to be proposed by the relevant developer. If such an approach were to be used for the I-SEM, it would be important to ensure that milestones were not grouped towards the end of development but also supported the early identification of failing projects.

Following a review of the milestones applied to GB Capacity, as well as those typically observed in EPC contracts, the following milestones[38] would seem to apply to all new capacity:

- Obtaining of all necessary consents
- Substantial Financial Completion
- Commencement of construction works
- Mechanical completion
- Completion of network connection
- First energy to network
- Start of performance/acceptance testing
- Provisional acceptance/Completion of performance testing
- Substantial Completion

4.6.14 Most of these milestones could be linked directly to specified events in other contracts, e.g. the EPC Contract or Connection Agreement, and so their occurrence can be established unequivocally. It is assumed that they can be established by reference to the pre-qualification documentation submitted before the Capacity Auction. Would any of the milestones require more detailed definition to be meaningful?

[38] The milestones may not always occur in the order shown

4.6.15 This set of milestones is spread across the commissioning window, but may potentially be sparse in the period prior to Substantial Financial Commitment. GB is attempting as part of the current consultation to address this problem by requiring various letters of commitment to be issued in this period. The initial response from the industry at a consultation forum was that these provided no greater security of delivery while placing a further burden on new Capacity Providers.

4.6.16 Any set of milestones will need to be kept under review and modified as new technologies are brought to market. Even so, it may occur that new capacity will be contracted for which one or more milestones is not relevant and there is no obvious analogue, e.g. mechanical completion has little relevance to batteries or solar PV. Under these circumstances, it should be possible to waive the need to report against the affected milestone.

4.6.17 In choosing the number and timing of milestones, the 'equity' assessment criteria will be the primary driver, seeking to balance risk between the market and project sponsor. As a result, there will be some tension between the 'stability' and the 'system security' and 'efficiency' criteria.

- **Stability**: if projects are to be investible, it will be important to avoid an excessively onerous number of milestones or being too prescriptive as to the timing of particular milestones. This will also be key if different projects and technologies are to compete fairly. The importance of the definition is strengthened if the milestones are used as the basis for changes in the value of the performance bond or for Reliability Option termination.
- **System Security** and **Efficiency**: if the system is to remain secure with sufficient capacity to meet demand and the reserve requirement, it is important to be able to identify potential project failure as early as possible – and where necessary replace failing projects. The later that a failing project is identified, the greater the potential costs of replacing it will be to the market.

Progress Reporting

4.6.18 To ensure efficient maintenance of sufficient Reliability Option capacity to meet the capacity requirement, it is important to be able to monitor the progress of new capacity from the Auction Date through to first delivery (or the closing of the Commissioning Window).

4.6.19 Regular reporting of progress against the Project Schedule submitted as part of the qualification process will provide the TSOs and RAs with advanced warning of potential future shortfalls in meeting the Capacity Requirement and could allow for adjustment of the capacity procured in future auctions.

4.6.20 In GB, the capacity market requires independently-verified reporting against four key milestones every six months. There is a live consultation to increase the reporting frequency to every three months prior to Substantial Financial Commitment for larger projects, though without independent verification for the additional reports. This increased reporting frequency in GB is part of a package of proposed measures responding to the termination by new capacity of capacity contracts won in the first T-4 Auction. In the I-SEM context, it will be important to ensure the value of any reporting is sufficient to justify its additional costs.

4.6.21 It seems sensible to require regular reporting of progress, but such reporting should not be excessively onerous on providers of new capacity. The reporting timetable should be consistent with any processes of the RAs or TSOs which would utilise such reports (e.g. Generation Adequacy Reporting) and, in particular, should be consistent with the ability to act within the capacity auction process.

4.6.22 Given the annual nature of the capacity procurement process, suitably timed six-monthly reports on progress would seem to be sufficient. Would some or all such reports need to be independently verified or would a requirement that such reports are the best estimate of progress be sufficient?

4.6.23 Reporting should be on a consistent, standardised basis to make monitoring straightforward. To manage the burden on new Capacity Providers, it seems sensible to co-ordinate the progress reporting under the CRM and DS3 where new capacity is delivering against both requirements.

4.6.24 The main tension in the assessment criteria around progress reporting will be between 'cost/practicality' and 'security of supply'.

- **Cost/practicality**: reporting places a cost burden on projects and also on the market to evaluate the reports. The cost to projects will be increased if independent reporting is required.
- **Security of supply**: more frequent reporting will provide better visibility of project progress and will aid the market in maintaining the agreed security standard. The likely annual nature of the auction process would suggest that, if suitably timed, biannual reporting should be sufficient.

Termination Conditions

4.6.25 It is desirable that failing projects are identified early – leading to the termination of the Reliability Option, and the potential to select another project to cover the resulting capacity shortfall. This argues for:

- Incentives on developers to "self terminate" early when they know (or strongly suspect) their projects will fail. This can be delivered by increasing the termination fee (and associated performance bond) progressively over the life of the development project; and

- By having clarity over the events that allow the central termination of Reliability Options.

4.6.26 There are a number of events that would clearly lead to termination of a Reliability Option, notably:

- If a project has not achieved Substantial Completion by the Long Stop Date ;
- Failure to achieve the Substantial Financial Commitment milestone

4.6.27 Consideration needs to be given as to whether any other milestones should also give rise to termination of the Reliability Option if they are not achieved within a defined period from the Auction Date.

4.6.28 Consideration should be given as to whether the Reliability Option should allow for "partial termination". This would allow the Reliability Option to take effect for new capacity which fails to achieve Substantial Completion but which is able to deliver at a reduced level. This additional milestone 'Minimum Completion' could only be invoked after the start of the first Delivery Year and could be triggered automatically or at the request of the Reliability Option holder once a certain threshold is crossed. Consideration is needed as to the level of this threshold: is the 50% value used in GB reasonable for the I-SEM?

4.6.29 If the concept of Minimum Completion is accepted, then the Performance Bond would be sacrificed pro-rata to the capacity that has not been delivered. For example, if only 60MW (as de-rated) is delivered against a 100MW Reliability Option then 40% of the Performance Bond would be sacrificed as a partial termination fee. This partial termination fee would be charged at the Long Stop Date on the basis of the (de-rated) capacity that had been physically proven at that time.

4.6.30 In GB, consideration is being given to adding a new termination event if false or mis-leading information was submitted as part of the qualification process. Should this be considered for the I-SEM?

4.6.31 If a Reliability Option is terminated at the Long Stop Date, but some or all of the underlying capacity does later become available, should this be able to participate in future capacity auctions as existing capacity? GB is consulting on sterilising such projects for a period of three years, i.e. they would be prevented from participation in the next two annual auctions. Is such an approach desirable in the I-SEM?

4.6.32 As before, when looking at the assessment criteria there is a need to balance risk and cost to the project against those of the wider market.

- **Stability**: if there are many potential triggers for termination and these are perceived as difficult to avoid, then this will make projects less investible and increase project costs and bids.

- **Security of supply**: if failing projects cannot be terminated early, there is an increased risk that the market will not be able to maintain the agreed security standard.
- **Efficiency** and **Competition**: an inability to terminate failing projects early will increase the cost to the market if in consequence it is forced to operate with a reduced security standard. However, if the risks of termination are perceived as being too high, participation in the capacity market may be reduced also leading to higher costs for consumers.

Performance bond

4.6.33 The SEM 15-044 and the recent CRM Decision Document state that new capacity should be required to post a Performance Bond. The idea is that this bond should provide "strong incentives to follow through with investment". The bond will be sacrificed under certain defined circumstances, e.g. if the project is abandoned.

4.6.34 The Performance Bond could fulfil a number of roles:

- to discourage participants participating in the Auction on the off-chance that they will be able to deliver capacity in the future;
- to compensate market participants from the increased costs or loss of revenue arising from the failure to deliver promised capacity;
- to encourage participants who entered the auction in good faith to exit early if it subsequently becomes apparent that they are unlikely to be able to deliver; and
- to reduce the level and degree of evidence required to meet the reporting requirements against the milestones.

4.6.35 The level of the Performance Bond should not act as an inappropriate barrier to entry. There is no point setting a level which discourages all or most potential new capacity from participating in Capacity Auctions.

4.6.36 Of the roles a Performance Bond could fulfil, only its role as compensation to the market for the increased costs or loss of revenue would appear to be susceptible to objective quantification. As a result, this should be used to set the basic level of the Performance Bond, though this may have to be adjusted downwards to achieve a level that the market would be willing to bear.

4.6.37 There are two primary methodologies which could be used to determine the level of market compensation arising from a failure to deliver new capacity.

- **Cost to Consumers:** The increased cost to customers of operating with a lower security standard than a LOLE of 8 hours. This could be evaluated by modelling the additional hours of LOLE that the capacity shortfall would cause and valuing these additional hours at VoLL. This valuation would use a very similar approach to that used to evaluate the cost/benefit of moving to a LOLE of 3 hours in SEM 15-044.

- **Cost to Capacity Providers:** The lost revenue to Capacity Providers could be estimated based on the cost of replacing the undelivered capacity in the Capacity Auction. Had the undelivered capacity not been selected in the original auction, the auction would have cleared at a higher price and this would have been received by all contracted Capacity Providers. So, the total loss of revenue to Capacity Providers is the cost of replacing the undelivered capacity plus the clearing price delta for all the other contracted capacity.

4.6.38 The determination of compensation will need to be made on a general basis rather than on the basis of a specific Capacity Auction. As a result, the calculation will need to be reviewed on a regular basis, e.g. every three years.

4.6.39 Evaluation of the increased cost to customers is relatively straightforward to perform prior to the first CRM Auction. However, evaluation of the lost revenue to Capacity Providers will be more difficult and require significantly more use of relatively unfounded assumptions until at least one CRM Auction has taken place. As a result, the SEM Committee is minded to use an estimate of the increased cost to customers to determine the level of Performance Bonds in the first instance. This decision can be reviewed once Auction results are available.

4.6.40 The level of compensation will depend on the time at which the Reliability Option was terminated. If termination occurs in time for replacement in the Capacity Auction immediately following the initial award, then costs will be incurred for a single year. For each subsequent year of delay, a further year of costs will be incurred by the market.

4.6.41 The level of compensation will not vary linearly with the size of the undelivered Reliability Option. Large Reliability Options will have a disproportionate impact. This has been recognised in the current GB consultation with a significantly greater burden in terms of reporting and the potential level of the performance bond proposed for application to units larger than 400MW. The adverse impact of non-delivery under large Reliability Options will be greater in the smaller I-SEM market than in GB.

4.6.42 Whilst it seems reasonable to recognise the greater impact on the market from the failure of large projects to deliver capacity, there may be issues with introducing this proposal in an I-SEM context. It creates a hard boundary to entry at 400MW and could render a whole class of potential capacity significantly less viable. Over the long term this could lead to a problematic plant mix and higher costs for consumers. A preferable option would be to set the level of Performance Bond to vary continuously with increasing project size, but not necessarily using a simple linear € per MW relationship. Either a piece-wise linear function or a non-linear curve could be used to better capture the relationship between project size and the impact of delivery failure on the market.

4.6.43 Having evaluated the estimated cost to the market of the failure to deliver capacity, this will need to be considered in the context of creating an excessive barrier to entry. For example, the initial level of the Performance Bond should be lower than the cost of achieving Substantial Financial Completion or it is effectively creating more onerous qualification requirements. In GB, the size of the initial Performance Bond was capped to 5000£/MW on the basis that any higher value would create too significant a barrier to entry.

4.6.44 As noted above, notional costs to the market of a failure to deliver increase linearly each year and this does provide an incentive for projects to exit a Reliability Option early if they expect to be unable to deliver. However, it may be practically infeasible to increase the size of the Performance Bond in this way without acting as a disproportionate barrier to entry.

4.6.45 It may be that a project will know that it will be unable to achieve its contracted capacity, even to within the tolerance acceptable for Substantial Completion, well before the end of the Commissioning Window. This information would be useful in appropriately setting the capacity to be bought in future Capacity Auctions. An argument could be made that financial incentives should encourage this early reporting, e.g. by charging a reduced partial termination fee at the time of notification, with the reduction based on how early the notification is made. Alternatively, it may be better to recognise that not all desirable actions can, or should, be encouraged through the application of targeted financial penalties using the Performance Bond. It may be better to rely on an obligation within the Implementation Agreement to report any known shortfall in the contracted capacity as early is practical. It may be sensible to apply this principle more widely, rather than follow the GB route of more detailed tailoring of termination fees and the associated regulations and rules to try and provide incentives for all outcomes.

4.6.46 When considering the Performance Bond as a barrier to entry, it is also important to consider any similar obligations arising from the DS3 auction process. The combined Performance Bonds from the two processes will need to be considered together when looking to set appropriate levels.

4.6.47 The cost to the market of a project terminating its Reliability Option does not change because a milestone is, or is not, achieved. As described above, this is based on the timing of the termination relative to the auction timetable. However, as milestones are achieved the level of financial commitment by the project tends to increase. If the performance bond is considered solely in terms of ensuring that the project is financially committed to delivery then an argument could be made that the level of the bond should reduce as milestones (or some of them) are achieved. E.g., in its proposed treatment of projects larger than 400MW, GB is planning either to reduce or not to further increase the level of the termination fee as the milestones on the way to Substantial Financial Completion are achieved in a timely manner.

4.6.48 An argument could be made that the level of the Performance Bond needs to be set at a lower level prior to Substantial Financial Completion as a project may seek to keep its costs to a minimum prior to this stage. Setting the Performance Bond at the full level need to compensate the market is most likely to act as a barrier to entry at this time.

After Substantial Financial Completion, it may be feasible to set the Performance Bond at (or closer to) the level needed to properly compensate the market.

4.6.49 If a project has not reached Substantial Completion by the start of the first Delivery Year costs to the market of non-delivery will continue and may continue to rise. However, the market is avoiding payment of the option fee on the delayed capacity. In consequence, it seems reasonable that the Performance Bond continues to be at risk, but an argument can be made that its value does not need to be increased.

4.6.50 One option would be to set an initial level for the Performance Bond which applies until the last date on which the impact of termination could be managed through the auction immediately following the initial award. The Performance Bond level is then increased to recognise the higher cost to the market of termination. The bond is further increased at Substantial Financial Completion and then held at this level. Ideally, the levels would be based on the costs to the market, but these may have to be reduced to allow for sufficient market participation.

4.6.51 To make further progress in establishing the level at which Performance Bonds should be set, modelling of the impact of the failure to deliver projects of a range of sizes (e.g. at 100, 200, 300, 400 and 500MW) needs to be performed to fully understand the cost impact on the market. This will help inform the choice to function used to link project size and Performance Bond and the extent to which attempts to recover the full cost of failure may create a disproportionate barrier to entry.

4.6.52 In the first years of the CRM, it is possible that the historic surplus of actual capacity over the Capacity Requirement will continue. In these circumstances, the costs of non-delivery may be lower than will typically be the case. This may provide an opportunity to phase in the level of the Performance Bond over time, e.g. starting at 50% of the intended long-term level, to help to manage the risk of introducing an unintentionally severe barrier to entry.

4.6.53 For any given Reliability Option, the value of the termination payments should be fixed at the time the Reliability Option is allocated.

4.6.54 As above, when looking at the assessment criteria there is a need to balance risk and cost to the project against those of the wider market.

Stability: the size of the Performance Bond and the length for which it must be held are costs to be borne by new projects. The scale of these costs could discourage participation in the market for all or some classes of potential entrants. The level needs to be set so as not to compromise the ability of good capacity projects to be brought forward.

Efficiency and **Competition**: there is a real cost to the market of a failure to deliver new capacity. This can be pre-estimated using the modelling methodology given above and would rise over the course of the Competition Window. More difficult to capture are the costs to the market from the reduction in competition which would arise if potential projects are discouraged by the cost of providing the Performance Bond.

Next Steps

4.6.55 To inform decisions relating to the level of the Performance Bond and its potential impacts on the provision of new capacity, modelling of the impact of the market of a shortage of capacity caused by non-delivery by a new project needs to be performed.

4.6.56 Discussion will continue with the DS3 team to achieve a common, consistent approach to cross-project issues, e.g. timing around the Commissioning Window, reporting of milestones and the level of the Performance Bond.

4.7 CONSULTATION QUESTIONS:

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

Reliability option contract length questions

A) Principle of Longer Term Reliability Options:

I. Do respondents agree that plant requiring significant investment should be able to avail of longer term Reliability Options?

II. Do respondents agree that existing plant should be restricted to reliability options with a term of 1 year?

III. Do respondents believe that longer term Reliability Options should only be available to new-build plant, or should also be available to existing plant where significant investment is being made to enhance or maintain its capability to provide capacity?

B) Classification of plant as new, upgrade or existing

I. Do respondents have a view on which approach should be used to classify capacity providers as "new", "upgrade" or "existing"?

II. Do respondents prefer the approach of classifying providers as "new", "upgrade" or "existing", please indicate your view of the criteria, evidence and thresholds that should be used to inform this classification.

C) Maximum available Reliability Option lengths

I. Do respondents have a view on the appropriate maximum Reliability Option lengths that should be available to new-build and upgraded plant?

II. How do respondents view the Reliability Option lengths in relation to the five generic frameworks set out in this section.

Stop-loss limits questions

D) Do respondents favour the I-SEM Capacity Year running from October to September, with annual stop loss limits applying over that I-SEM Capacity Year?

E) Do respondents believe that "per event/day" and "per month" limits are required in addition to the annual stop loss limit?

F) Which approach do respondents favour for the definition of the Per Day/event limit?

G) Please provide views on the appropriate levels for the each of the proposed stop loss limits.

Commissioning Window and Implementation Agreements questions

H) Is a period of four years from the Auction Date to the start of the first Delivery Year appropriate?

I) Does setting the Long Stop Date at 18 months after the start of the first Delivery Year strike the correct balance between the costs incurred by the market and the ability for delayed or longer-running capacity projects to be completed?

J) Are the proposed milestones reasonable?

K) Are there any other milestones, especially prior to Substantial Financial Commitment, which could be used to add security to the delivery of new capacity?

L) What proportion of the contracted capacity is appropriate to use to identify Substantial Completion?

M) Is six-monthly reporting appropriate?

N) Do any (or all) of the reports need to be independently verified?

O) Does 18 months provide sufficient time after the Auction Date to achieve Substantial Financial Commitment?

P) Is it appropriate to terminate a Reliability Option for failure to achieve Substantial Financial Commitment?

Q) Should failure to achieve any other milestones (within a suitable window) trigger termination of the Reliability Option?

R) Is it appropriate to partially terminate a Reliability Option if it can achieve 'Minimum Completion? What level should be set for Minimum Completion?

S) If a Reliability Option is terminated under the terms of the Implementation Agreement, should this project be 'sterilised' for a period of time following the termination and be unable to participate in capacity auctions?

T) Should the I-SEM consider terminating Reliability Options if the information submitted as part of the qualification process is discovered to be false or mis-leading?

U) Do respondents agree that the level of the performance bond should be based on a pre-estimate of the cost to the market of non-delivery of contracted capacity?

V) Do respondents agree with the principle that the level of performance bond should rise over time, reflecting increased costs to the market? If not, what alternative principle should be used and why?

W) At what level in €/MW does the performance bond create a serious barrier to entry? Does this differ for small vs large plant or for different technologies?

X) Do respondents agree with the principle that use of a fixed €/MW level for all participants, regardless of size, to set the size of the performance bond does not fully capture the costs and risks to the I-SEM and that a more complex approach is needed? Do participants have an alternative preferred method for handling the greater risks to the I-SEM created by larger new capacity projects?

Y) How should the level of the performance bond change over time? Should this have any link to the milestones?

Z) Do you consider that the Time To First Delivery (/Time to LSD) proposed here for the CRM should also apply equally to the delivery of System Services under the DS3 arrangements? If you consider that the time (s) should be different, on what basis / what rationale should they differ?

Please provide your rationale for your response to all of the above questions.

5. LEVEL OF ADMINISTERED SCARCITY PRICE

5.1 INTRODUCTION

5.1.1 The SEM Committee have decided that Administered Scarcity Pricing should be introduced into the energy imbalance price. This Administered Scarcity Price will apply when there is insufficient available capacity to cover the combination of demand and the target level of operating reserve[39].

5.1.2 The level of the Administered Scarcity Price acts as a floor on energy prices[40], and will increase as the margin of spare capacity is eroded, ultimately resulting in the forced reduction in the load of some or all customers in the I-SEM. This increase in the Administered Scarcity Price will be controlled by a five-part piecewise linear function (see Figure 12), the parameters of which will be determined by the SEM Committee on a periodic basis. In Figure 12 the Administered Scarcity Price starts applying at point B, when the available capacity drops below the target operating reserve, and the price increases further until the point when full load shedding occurs at point A, when the Full Administered Scarcity Price applies.

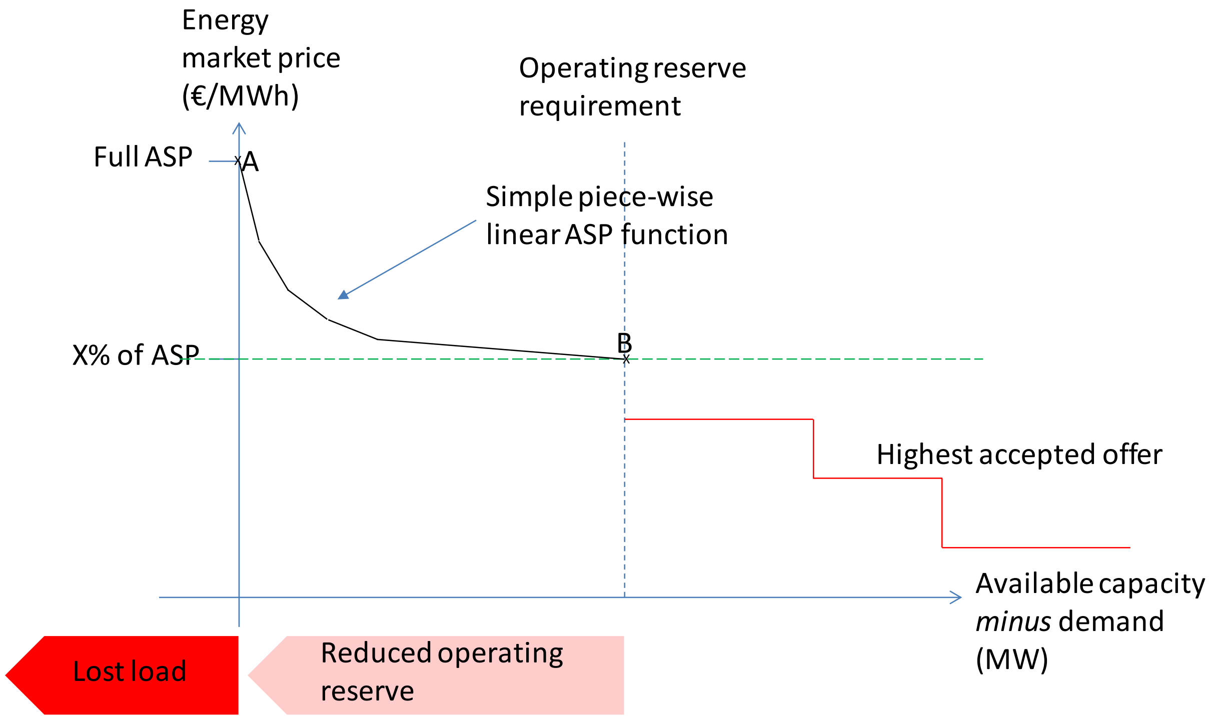
5.1.3 This consultation considers a number of issues relating to the precise definition of the Administered Scarcity Price, as well as the initial parameters for the piecewise linear function. Specifically, this covers:

- The appropriate level for the Full Administered Scarcity Pricing, i.e. the level of Administered Scarcity to apply in the event of "load shedding";
- The precise definition of load shedding- i.e. when the Full ASP will apply;
- The precise definition of target operating reserve requirement, and what advance signalling of potential scarcity should be made available to the generality of the market by the TSOs; and
- Whether it is appropriate to have a phased approach to introduction of ASP, introducing ASP at a lower level during some transition period;

[39] Scarcity will not apply where operating reserve is reduced below target levels because the TSO uses reserve which has already been deployed (for instance to cover a forced outage), but additional capacity is available to replenish reserve

[40] The price during scarcity will be the higher of a market determined price and the relevant Administered Scarcity Price. Therefore if an accepted market based bid is higher than the Administered Scarcity Price, the imbalance price can rise to reflect the market based bid

Figure 12: Piecewise linear Administered Scarcity Pricing Function



5.2 DEFINITION OF LOAD SHEDDING

5.2.1 Load shedding is the point at which Full Administered Scarcity Price (FASP) applies, i.e. point A in Figure 12.

5.2.2 SEM-15-103 stated that, broadly speaking, the definition of full load shedding to correspond to the current definition of Eirgrid red alerts. Eirgrid issues a red alert when one of the following four has occurred:

- The system frequency deviated significantly below normal levels;
- System voltages deviated significantly below normal levels;
- Consumer load has been shed (involuntarily); or
- In the period immediately ahead there is a high risk of failing to meet system demand or maintaining normal voltage and frequency.

5.2.3 We would anticipate that load shedding would be deemed to have occurred and the Full Administered Scarcity Price to apply when any of the first three of the above events has occurred. The last events that can give rise to a red alert are a forecast of an event, not an actual event, so should not be considered load shedding.

5.2.4 The first three events that give rise to an Eirgird Red Alert are similar to those used for the use of Value of Lost Load (VoLL) in GB electricity markets. This would occur when a

Demand Control Event occurs. A Demand Control Event is one of three events defined in OC6 of the GB Grid Code, specifically:

- Demand disconnection;
- Voltage reduction; or
- Low Frequency Demand Disconnection.

5.2.5 Respondents are asked to provide their views on the following questions:

- Do you agree that the definition of full load shedding should be based on the actual (as opposed to forecast) events that give rise to an Eirgird Red Alert (frequency drop, voltage drop, or involuntary load reduction)?
- How far should voltage fall before full load shedding is judged to have occurred?
- How far should frequency fall before full load shedding is judged to have occurred?
- For how long should any drop in voltage or frequency be sustained before full load shedding is judged to have occurred.

5.3 LEVEL OF FULL ADMINISTERED SCARCITY PRICE (FASP)

5.3.1 The SEM includes two parameters which, at first sight, could provide a basis for the FASP. These parameters are:

- **Value of Lost Load (VoLL)**: VoLL is defined as the value (in €/MWh) which "represents the end-customer's willingness to lose supply" and as the value that "consumers would place on a unit of non-delivered electricity". VoLL is used in setting the price paid for capacity in the SEM, and does not directly impact energy prices. In SEM-15-053, the SEM Committee published the value of VoLL to apply in 2016 which is €11,017.98/MWh; and
- **Pool Price Cap (PCAP)**: This is an actual cap on energy prices in the SEM, and is set to €1000/MWh for 2016.

5.3.2 This SEM VoLL still represents the best estimate of the opportunity cost to customers of lost load on the island of Ireland. If the I-SEM were an isolated system, and cost reflectivity were the sole criteria then it is arguable that it would be appropriate to set the Full ASP at this level. Any Supplier would be incentivised to work with their customers to ensure that demand response was provided by any customer whose opportunity cost was less than that of the VoLL, ensuring that the full range of demand response was possible, promoting optimal system security.

5.3.3 Whilst cost reflectivity is an important driver of economic efficiency and promoting optimal system security, there are reasons why it may be appropriate to set Full ASP at a lower level. These include:

- Any incentive effect arising from how the level of FASP could interact with an EU imposed price cap on the Day Ahead Market (Euphemia price cap of €3,000/MWh);
- The impact of the level of FASP on Capacity Provider and Supplier risk
- Impact on the actual flows between the I-SEM and GB at times of co-incident scarcity – noting that GB has set its equivalent price at £3,000/MWh for an introductory period, switching to £6,000 from the start of winter in late 2018. These are broadly equivalent to €4,170/MWh and €8,340/MWh respectively[41].

5.3.4 This gives rise to a number of options for the level of FASP:

- **VoLL:** FASP is set to the current estimate of the Value of Lost Load for the I-SEM system. For 2016 this is €11,017.98. Under the current SEM, this value will increase on an annual basis in line with inflation.
- **EU Consistent:** FASP is set consistent with its equivalent value in neighbouring electricity markets. This currently is the GB market, implying a value of €4,170/MWh rising to €8,340/MWh from late 2018;
- **Euphemia Cap:** FASP is set at the Euphemia cap for the day-ahead market. This is currently €3,000/MWh
- **PCAP:** FASP is set at the current (€1,000/MWh) Pool Price Cap in the SEM

5.3.5 The impact of these options on each of the I-SEM assessment criteria is discussed further in the following paragraphs:

- **Internal Electricity Market:** The European Commission has recently stated that *"an essential condition for electricity markets sending the right price signals for investment in adequate capacity is to allow prices to reflect scarcity"[42].* For this statement to work and deliver the required security of supply, prices have to be allowed to rise to VoLL. Considering other prices set within the target model, and in neighbouring electricity markets:
    - The Euphemia day-ahead price cap of €3,000 looks a low estimate of the true value of scarcity given the estimates of VoLL in the I-SEM and GB- although the current Euphemia cap is subject to consultation and review;
    - GB has already adopted scarcity pricing which transitions to a level that is similar to the SEM VoLL. This has a FASP of £3,000/MWh initially, rising to £6,000/MWh

  The above position would argue that FASP should be set at

    - VoLL; or
    - A level no lower than that in GB – to avoid distortions to trade between GB and the I-SEM at times when the Euphemia price cap does not apply.

[41] This is based on an exchange rate of £1.39/€
[42] "Launching the public consultation process on a new energy market design", Brussels, July 2015

- **Security of Supply:** In general, a higher value of FASP is consistent with improved Security of Supply – as it provides greater potential revenue for investors in capacity (notwithstanding they can get revenue from Reliability Options). The theory behind the (LoLE) generation security standard used for the I-SEM suggests that we should use a FASP set to the same level as VoLL as:
  - A higher level would lead to more investment in capacity than is required to meet the security standard; and
  - A lower level would lead to less investment in capacity than is required to meet the security standard.
- **Competition:** Some have argued that the prospect of high energy prices will act as a barrier to entry for new Suppliers. This is potentially true; however:
  - Reliability Options will protect Suppliers against excessively high prices (whilst retaining incentives for those Suppliers to manage the load of their customers); and
  - The European Commission's statements[42] of scarcity pricing suggest that such high prices may, in any event, become a feature of the European Target Model

  In addition, any difference between the GB and I-SEM values of FASP has the potential to disrupt effective competition between GB and I-SEM capacity providers. Taken together, this argues for a value of FASP which is either set at VoLL, or is set close to the equivalent GB value.

- **Equity:** Arguably the "VoLL" option is the most equitable, as it maintains incentives on customers (via their Supplier) to reduce their load if prices go above their specific VoLL. The design of the I-SEM Reliability Options mean that this effect is retained – as Suppliers will retain the full benefit of selling back power they have purchased at the Day Ahead stage.
- **Stability**: The "Stability" assessment criteria is related to having arrangements that investors understand. This would argue for setting FASP using an option which has a clear rationale. This could be satisfied by any of the options other than the "PCAP" option. That is, stability would be satisfied by stating that the principle that FASP will be:
  - Linked to the equivalent GB price;
  - Set at VoLL; or
  - Linked to an EU (e.g. Euphemia) price cap.
- **Efficiency:** Some have argued that setting the FASP to a level above the Euphemia price cap would lead to a loss of efficiency, as generators withhold power from the day-ahead market to sell in later (higher priced) markets. In practice, this effect is:
  - **Potentially unavoidable:** It is rational that prices should rise at times of scarcity. The Administered Scarcity Price acts as a "fall back" to cover the

fact that, with the current maturity of electricity markets, customers (and their Suppliers) do not effectively signal the price at which they are prepared to load manage. This need for high prices at scarcity has been acknowledged by the European Commission in their recent consultation[42]

- **Mitigated through the Reliability Option design:** It is expected that the bulk of capacity in the I-SEM will be contracted through Reliability Options. These Reliability Options will limit the net energy price paid for contracted capacity to the Reliability Option Strike Price. This Strike Price is expected to be lower than the Euphemia Price cap, so would negate any incentive to withhold power at the Day Ahead Stage.
- **Addressable through trading:** It is envisaged that generators will be able to both buy and sell in the Day Ahead market. This will allow a generator that believes prices will be higher in later markets to sell the output (e.g. at avoidable cost) and then buy it back at the Euphemia price cap. This has been referred to as "virtual bidding" in the previous CRM consultations and it associated workshops.
- The "Environmental", "Adaptive" and "Practicality/Cost" assessment criteria each have little or no impact on the choice between options for the level of FASP

5.3.6 The "Environmental", "Adaptive" and "Practicality/Cost" assessment criteria each have little or no impact on the choice between options for the level of FASP, definition of target operating reserve and setting of ASP Function

5.3.7 Administered Scarcity Pricing starts to apply when there is insufficient available capacity to maintain the target operating reserve (at point B in Figure 12). In this sub-section we discuss how to define target operating reserve.

5.3.8 The TSOs (Eirgrid and SONI) operate a common operating reserve requirement across the island of Ireland. The current target operating reserve is set out in Figure 13. The requirement is primarily driven in practice by the size of the largest in-feed, which varies dynamically and could be around 500MW if the East-West interconnector is importing at full capacity, or might be driven at other times by the size of one of the CCGTs or a Money point unit (285MW).

5.3.9 However, the target operating reserve requirement is likely to change as a result of the DS3 programme and the move to target System Non-Synchronous Penetration of 75% by 2020.

Figure 13: Current All-Island Reserve Requirements

2. Operating Reserve Requirements

The following tables show the operating reserve requirements on an all-island basis and in each jurisdiction.

Category	All Island Requirement % Largest In-Feed	Ireland Minimum[1] (MW)	Northern Ireland Minimum (MW)
POR[2]	75%	110 / 75	50
SOR	75%	110 / 75	50
TOR 1	100%	110 / 75	50
TOR 2	100%	110 / 75	50

1. Ireland Lower values apply from 00:00 - 07:00 inclusive
2. Minimum values of POR in each jurisdiction must be supplied by dynamic sources

2.1 Operating Reserve Definitions

	Delivered By	Maintained Until
Primary (POR)	5 seconds	15 seconds
Secondary (SOR)	15 seconds	90 seconds
Tertiary 1 (TOR1)	90 seconds	5 minutes
Tertiary 2 (TOR2)	5 minutes	20 minutes

2.2 Source of Reserve

	Ireland	Northern Ireland
Dynamic Reserve	Synchronised Generating Units	
Static Reserve	Turlough Hill Units when in pumping mode Interruptible Load: Standard provision: 45MW (07:00 – 00:00) EWIC Interconnector (up to 100MW)	Moyle Interconnector (up to 50MW)
Negative Reserve (Defined as the MW output of a conventional generator above its minimum load)	100MW	50MW

Source: http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_25_April_2015.pdf

5.3.10 The SEM Committee has decided that ASP will apply whenever there is insufficient available capacity to meet target operating reserve. Note that Administered Scarcity Pricing will not apply at times when there is sufficient available capacity, but it cannot start/ramp-up fast enough leading to a short term reduction in operating reserve- a frequent event.

5.3.11 The TSOs will be responsible for monitoring available capacity in real time.

5.3.12 The SEM Committee has decided to implement a simplified piece-wise linear pricing function to calculate the Administered Scarcity Price during a period where there is insufficient capacity to maintain target operating reserve, but load is not being shed. The BM price in any such Settlement Period will be the higher of the simplified piece-wise linear ASP function, or the BM price as otherwise determined by the I-SEM ETA Markets

Paper (SEM-15-064). As further stated in SEM-15-103, the SEM Committee has asked the TSOs to begin developing systems to accommodate a 5 piece-linear function, i.e. with 4 elbow points.

5.3.13 However, the SEM Committee is consulting on:

- The parameters that define the piece-wise linear function;
- What notice market participants should be given by the TSO that Administered scarcity is likely to be triggered, and whether and when the TSO should publish forecasts of any ASP.

5.3.14 The piece-wise function should be a reasonable linear approximation to the Loss of Load Probability (LoLP) x Full ASP, so the piece-wise linear function should be reasonable linear approximation to the LoLP function. However any accurate LoLP calculation is dynamic. At a time when there is insufficient capacity available to meet target operating reserve, the LoLP will depend upon a number of factors including, how many MW of operating reserve remain, the reliability of the available sets, and whether the reserve is distributed over a large number of small sets or a small number of large sets.

5.3.15 We consider that it is impractical to have a dynamic LoLP calculation from the inception of the I-SEM. We note that Ofgem have reached the same conclusion with regard to their Reserve Scarcity Pricing function which was incorporated into the revised GB BM cashout arrangements from 5 November 2015. GB have started with a static LoLP function, and plan to move to dynamic calculation by winter 2018/19.

5.3.16 Therefore we propose to ask the TSOs to estimate a static all-island LoLP function annually, as a function of the MW of remaining reserve. They will then determine the value of X in Figure 12, and the parameter of the pricing function between points A and B in Figure 12. They should do this a number of months before the start of the Capacity Delivery year, and the function will be subject to approval by the SEM Committee.

5.3.17 Ideally, these parameters would be set in advance of the T-1 auctions (it will not be feasible or sensible to fix the function many years in advance, so that it is known before the T-4 auctions), and we would like feedback on the appropriate value of X, and when it should be set in relation to the timing of the T-1 auctions.

5.3.18 Once set, all parameters for the Administered Scarcity Pricing Function would be kept under review by the SEM Committee

5.4 INTRODUCTORY ARRANGEMENTS

5.4.1 The discussion in 5.3 relates to the value of FASP that should be used on an enduring basis.

5.4.2 The approach taken to the introduction of Administered Scarcity pricing in GB suggests there is a benefit of starting with a low value for FASP (at point A in Figure 12), and progressively increasing its level over time. If we decided to introduce a lower level of FASP initially, then the presumption is that the Administered Scarcity Price would be lower throughout the range from point B to point A in Figure 12)

5.4.3 In evaluating this approach to phase in the FASP against the I-SEM assessment criteria:

- An initial low value for FASP would score poorly against most of the criteria referenced in 5.3 above – as these criteria typically argue for a value related to one of VoLL or the GB equivalent of FASP; however
- A progressive increase in FASP can be argued to be consistent with the **"Stability" criteria** – as it will have the effect of smoothing any changes between the level of energy prices that arise under the SEM and I-SEM. To maintain the desirable "stability" effects, we need to ensure that investors understand:
    - The principles that will ultimately guide the enduring level of FASP; and
    - The parameters (such as time window) that cover the progressive increase in the level of the FASP

5.4.4 With the above factors in mind, we suggest that we need to set at the outset:

- How long we will keep the value of FASP below the level envisaged for the enduring FASP (the FASP Introductory Period)?
- What value should be used for the FASP at I-SEM go-live? And
- Whether the FASP should remain constant during the FASP Introductory Period, or increase progressively towards the enduring FASP?

5.4.5 To support response to this consultation, we consider the following options for each of the above points:

- That the "FASP Introductory Period" should be 3 years. This is similar to the introductory period for the GB FASP;
- That the FASP value at I-SEM go-live should be linked to the Euphemia price cap; and
- That the FASP value should increase annually within the FASP Introductory Period. This increase should follow a "straight line" between the FASP value at I-SEM go-live and the enduring FASP value. This is arguably most consistent with the "Stability" assessment criteria – as it progressively reveals the impact of any increase in FASP, reducing investor uncertainty.

5.5 CONSULTATION QUESTIONS

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

A) Which of the options do respondents prefer (and why) for the enduring level of the Full Administered Scarcity Price (FASP)?

   I. VoLL;
   II. EU Consistent (e.g. with GB);
   III. Euphemia Cap; or
   IV. Existing SEM PCAP

B) Do respondents agree with the definition of full load shedding (when Full ASP applies) as set out . If not please explain why, and your proposed alternative definition.

C) Do respondents agree that virtual bidding removes any incentives on capacity providers to withhold power from the DAM or the IDM to sell in the BM? Do you agree that this applies regardless of what market power controls are placed on DAM, IDM and BM bids? Do you agree that this applies regardless of the level of the Full ASP? If you do not agree, please explain why.

D) If stakeholders consider that it is appropriate to set the Full ASP at a lower level for an introductory period they should also set out, how long that introductory period should be and why, or alternatively the principles that the SEM Committee should employ in deciding when to move from the introductory full ASP to the higher rate full ASP.

E) If you favour a different level of Full ASP, either for an introductory period, or after any introductory period, please indicate the level and justify your response.

F) Do respondents agree with the proposed approach of using a static approach to setting the piece-wise linear ASP function at the inception of the I-SEM, and if not why not? If yes, do you agree with the proposed approach of setting the piece wise linear equation as a function of the remaining MW of available operating reserve?

G) What should the value of X in Figure 12 be?

H) How far in advance of the start of the Capacity Delivery Year should the piece-wise linear function be set. Does this need to be before the T-1 auctions?

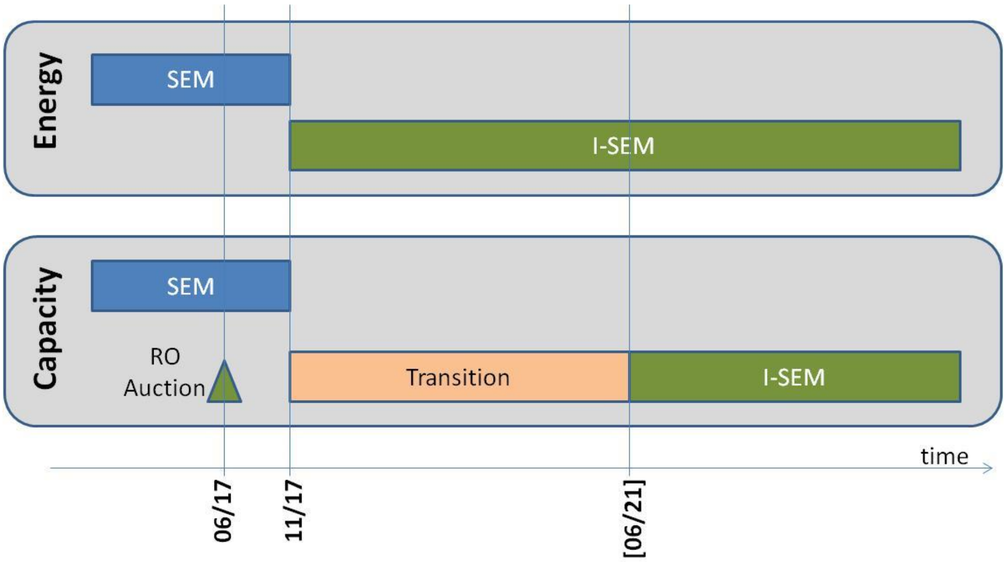
I) Do respondents think that any changes need to be made to the governance of the target operating reserve policy. If yes, what are these changes?

Please provide your rationale for your response to all of the above questions.

6. TRANSITIONAL ISSUES

6.1.1 As illustrated in Figure 14, the anticipated lead time[43] between the first main auction for the allocation of Reliability Options and the start of those options leads to transitional period. Neither the existing SEM CRM, nor the Reliability Options from that first auction, will be paying for Capacity that operates during this transitional period. We have to decide which providers are paid for capacity, and the rate at which they are paid.

Figure 14: Movement from SEM CRM to I-SEM CRM.



6.1.2 It is anticipated that the bulk of the required capacity for a given year will be purchased "n[44]" years ahead of that year. This "n" year lead time allows potential new-build capacity to compete alongside existing capacity to be awarded a Reliability Option. There will also be annual auctions covering the delivery of capacity for the following year – which will be used to fine-tune the level of capacity that is contracted.

6.1.3 For each year following the initial "n" years, these arrangements will have procured sufficient capacity; however, there will be a shortfall for this initial period. There are a number of options for how we address this shortfall, notably including:

- **Option 1 - Auction each year separately**: Under this option:
  - Each round of capacity auctions would procure the balance of capacity required for the Capacity Year immediately following those auctions, as well as the bulk of the capacity required for Capacity Year + n

[43] This lead time is illustrated as

[44] "n" needs to be sufficiently long to allow for the typical time to build new plant – with a value of 4 years having been adopted in a number of other Capacity Markets

- For the first “n” years, the year-ahead auctions will be procuring all of the capacity required for that capacity year,

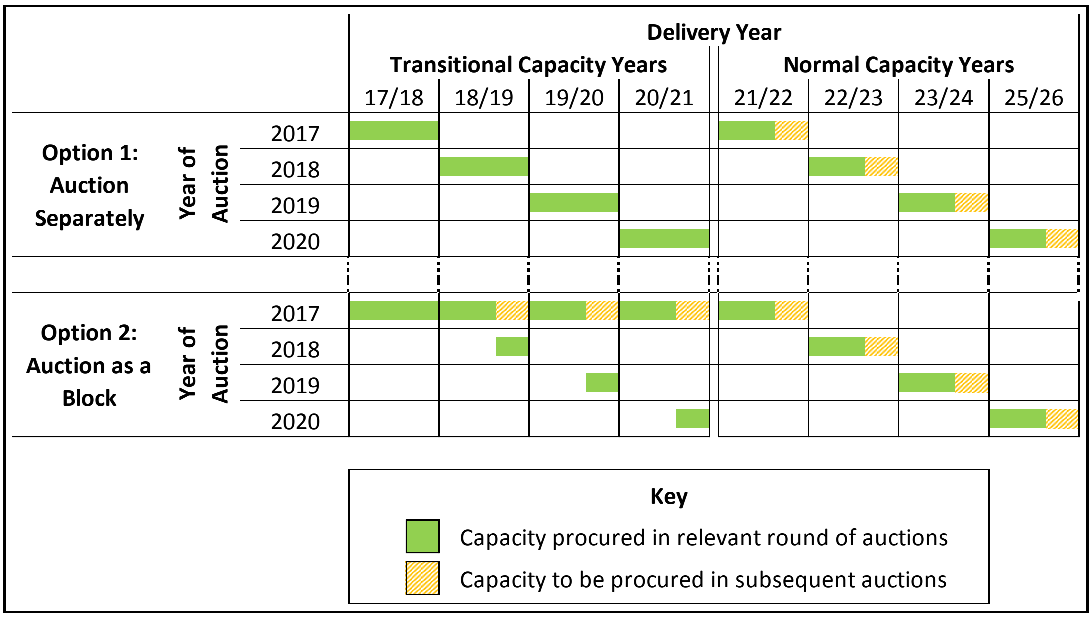
- **Option 2 - Auction as a block:** Under this option:
  - The first (June 2017) round of capacity auctions would procure the bulk of the required capacity required for each of the transition years, as well as for the following Capacity Year (year + n).
  - The auction for the transition period would be a combinatorial auction – similar to that proposed for DS3[45]. Capacity providers would submit one or more bids for each of their plant. Each bid would contain a price (€/MWyear) and the quantity of capacity offered in each of the transition years. The Auction would then select the least-cost combination of bids to meet the capacity requirement across the transition period.
  - Each subsequent annual round of auctions would procure the bulk of the required capacity for “year + n”, as well as a small amount of capacity to fine-tune the level of contracted capacity for the Capacity Year immediately following those auctions.

- **Option 3 - Do Nothing:** Under this option, Capacity Providers receive no Capacity Payments during the transition period. This option would leave Suppliers fully exposed to market prices above the Reliability Option Strike price (assuming those Suppliers are unable to otherwise contract their requirements in forward markets). As such, it may be necessary to also set the Administered Scarcity Price to relatively low levels during the transition period.

6.1.4 The difference between Options 1 and 2 is illustrated in Figure 15 below – based on a 4 year transitional period (n=4).

[45] SEM 14-108, DS3 Systems Services Procurement Approach and Emergent Thinking, December 2014

Figure 15: Options 1 and 2 for procuring capacity to cover transitional capacity years



Each of these options has different strengths and weaknesses when assessed against the I-SEM Assessment criteria as set out below:

- **Option 1 - Auction Separately:** This option scores well against most criteria, but scores less well against the "security of supply" and "competition" criteria. The key weakness is that this approach could leave us short of capacity towards the end of the transition period. This would occur if the plant that is needed late in the transition period has closed as a result of not being awarded Reliability Options in earlier auctions.
- **Option 2 - Auction as a Block:** This option scores well against most criteria, with the possible exception of competition. It addresses the weakness in Option 1 by considering the capacity requirements for the complete transition period as part of the June 2017 Auction. This will look at the most economic procurement of capacity for the entire transition period – which may include procuring a plant for the entire period even if that plant is only required towards the end of the period. However, combinatorial auctions may allow pivotal bidders to exercise market power more easily. We discuss this issue in more detail below.
- **Option 3 – Do nothing:** This option potentially scores well against the "Internal Energy Market" and "Practicality / Cost", but achieves a balanced to poor score against all other criteria. Notably:
  - **Internal Electricity Market:** This option is consistent with at least one view emerging from the European Commission – that energy only markets can work if prices are allowed to rise. It is also consistent with the State Aid Guidelines – which state that the price paid for capacity should tend to zero when there is a surplus of capacity.

- It is notable that for this option to score high against these criteria, it is a requirement that prices are allowed to go to very high levels. If the Administered Scarcity price is fundamental to those high prices, combining this option with a low Administered Scarcity Price may lead to a low score against this criterion.
- **Practicality/Cost:** This is the lowest and simplest option to implement.
- **Security of Supply:** Under this approach, there is a risk that energy revenues are insufficient to cover the average costs of capacity providers, meaning that plant is closed or mothballed to an extent that would breach the (8 hour LOLE) I-SEM generation security standard.
- **Competition, Environment and Equity:** This option provides no opportunity for new entrants to compete with existing plant (i.e. efficient entry and exit). In addition, under the I-SEM, Demand Side Participants will only receive a payment for capacity, so would be precluded from participating in the I-SEM.
- **Stability:** This option introduces a step change between the SEM and transition, and between transition and the I-SEM capacity remuneration mechanism. This lack of stability has a potential negative impact on investor confidence and hence cost of capital (albeit the impact of this may be low given the surplus of capacity in the I-SEM, and hence the limited need for capacity investment)

6.1.5 In a combinatorial auction (Option 2) a capacity provider could bid price / quantity pairs separately for 2017/18, 2018/19 and 2020/21, but would not be bound to deliver capacity in 2020/21, if it did not receive a capacity payment in 2017/18. The auctioneer takes this into account, and procures capacity for all three years in combination. As a result, the bidders that win a contract for 2017/18 are not necessarily those who have bid cheapest in 2017/18. Suppose that Capacity Provider A bids €10/kWyear for 2017/18 but bids €50/kWyear in 2020/21 (e.g. because it needs significant investment to prolong its life), but Capacity Provider B bids €20/kWyear for both years.

6.1.6 In a combinatorial auction, the auctioneer may find that it is more economic to select Bidder B for both years, whereas if they were separate auctions, the auctioneer would select Bidder A for 2017/18 and Bidder B for 2020/21. The implication is that in a combinatorial auction:

- There is a separate winner determination process and price determination process;
- Prices are less transparent, as they are the outcome of price determination algorithms, not merely the result of stacking bidder for each year in price order until the requirement for that year is met; and
- There is a greater opportunity for a bidder with market power in one product (one Capacity Delivery year in this case) to be able to exercise market power across all products (all years) because the bids are contingent.

6.1.7 There are ways of mitigating market power, such as:

- Requiring certain capacity providers to bid, at any price in excess of a maximum exit price (called a price-taker threshold in the GB capacity auctions); and
- Introducing sloping demand curves.

6.1.8 We discuss the auction design and ways of mitigating market power in Consultation 3. However, at this stage we seek early feedback from relevant stakeholder on whether they see any advantage in the combinatorial approach (Option 2), provided that adequate market power controls can be implemented.

6.2 CONSULTATION QUESTIONS

6.2.1 The SEM Committee welcomes views on all aspects of this section, in particular:

A) Which of the suggested options (annual auction, block auction, do nothing) do you prefer?

B) If you prefer the do-nothing auction, do you believe this should be accompanied by relatively low levels of Administered Scarcity Price?

C) Are there any other transitional issues respondents feel that we should take account of when implementing the CRM?

Please provide a rationale for your responses.

7. RESPONDING TO THIS CONSULTATION

7.1.1 Responses to the consultation paper should be sent to Natalie Dowey (natalie.dowey@uregni.gov.uk) and Thomas Quinn (tquinn@cer.ie) by 17:00 on Friday 5th February. 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
FASP	Fast Administered Scarcity Price
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