# Integrated Single Electricity Market (I-SEM)

# Capacity Remuneration Mechanism Detailed Design
# Second Consultation Paper
# SEM-15-014

## A Submission by EirGrid and SONI

## 8th February 2016

**Contents**

# 1 EXECUTIVE SUMMARY

EirGrid and SONI welcome the SEM Committee's second consultation on the detailed design of the Capacity Remuneration Mechanism in the I-SEM.

As an enduring approach to the treatment of cross-border capacity, EirGrid and SONI would favour a regional solution developed in cooperation with neighbouring markets and in the context of upcoming Energy Union decisions at a European level. In the interim, we would suggest that an interconnector-led approach offers a solution that is both consistent with the treatment of cross border capacity in the GB Capacity Market and can be implemented in time for I-SEM go-live.

We believe that efficient secondary trading arrangements are crucial to the success of the CRM and that all the options consulted on are potentially implementable for I-SEM go-live provided a relatively standard approach is adopted. We believe that the product length should be aligned insofar as possible with the arrangements for DS3 system services. We suggest that secondary trading offers a potential alternative to stop loss limits but if these are still deemed necessary , we suggest that they are implemented on an annual basis only and set at the highest level to reduce suppliers' exposure to scarcity prices.

Any performance bonds need to be considered in the context of the rules-based institutional arrangements and the level of performance bonds should be set to encourage providers to trade out of positions that they cannot physically back as early possible to avoid the need to draw down on any performance bond.

In relation to administered scarcity pricing, we suggest that the reserve margin be based on actual operating or replacement reserve rather than the total available capacity (which may include offline units not capable of responding in the timeframe required). This in our view would result in better outcomes as the price would signal the imminence of a demand control event and encourage the strong response from capacity providers necessary to mitigate such an event. It would also align our arrangements with the scarcity pricing in GB which is based on activation of short term operating reserve.

Finally, on the transitional arrangements, either the Annual Auction or the Block Auction would work in our view with a slight preference for the Annual Auction as it allows the opportunity to address any issues encountered in the previous year's auction. The third option of do-nothing is not an attractive option in our view as it would represent a significant disruption to the investment in capacity in Ireland and Northern Ireland. The implications of a gap in CRM funding are highlighted in the 2016 – 2025 Generation Capacity Statement produced by SONI and EirGrid in response to a request from the RAs and Government Departments.

Finally, EirGrid and SONI would like to reaffirm our commitment to working with both the industry and the Regulatory Authorities to assist in the development of effective and appropriate I-SEM arrangements and to support the delivery of the new market arrangements by Q4 2017.

# 2 INTRODUCTION

## 2.1 EIRGRID AND SONI

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

Both EirGrid, and its subsidiary SONI, have been certified by the European Commission as independent TSOs, and are licenced as the transmission system and market operators, for Ireland and Northern Ireland respectively. EirGrid also owns and operates the East West Interconnector, while SONI acts as Interconnector Administrator for both of the interconnectors that connect the island of Ireland and GB.

EirGrid and SONI, both as TSOs and MOs, are committed to delivering high quality services to all customers, including generators, suppliers and consumers across the high voltage electricity system and via the efficient operation of the wholesale power market. EirGrid and SONI therefore have a keen interest in ensuring that the market design is workable, will facilitate security of supply and compliance with the duties mandated to us and will provide the optimum outcome for customers.

This response is provided on behalf of SONI and EirGrid in their roles as TSO and MO responsible for Capacity Mechanism Delivery and Capacity Mechanism Settlement..

## 2.2 STRUCTURE OF THE RESPONSE

This document sets out EirGrid and SONI's response to the SEM Committee's second consultation on the Capacity Remuneration Mechanism Detailed Design (SEM-15-014) published on the 21$^{st}$ Dec 2015.

Section 3 of the response provides an overview of the key points that EirGrid and SONI would like to emphasise as being of most importance, in their roles as TSO and MO.

Section 4 of the response provides our detailed comments on the specific chapters and sections of the consultation paper, including responses to the questions posed in the paper, which underpin the key points in Section 3.

# 3 KEY POINTS

## 3.1 CROSS-BORDER CAPACITY

As an enduring approach to the treatment of cross-border capacity, EirGrid and SONI would favour a regional approach developed in the context of upcoming Energy Union decisions at a European level. We believe there are significant challenges in the development of participant-led approach and that these challenges would be best addressed at a regional level in cooperation with the relevant parties in our neighbouring markets (in particular GB). We believe that implementation of a provider-led solution prior to the development of a regional approach would be premature. In the interim, we would suggest that an interconnector-led approach offers a solution that is both consistent with the treatment of cross border capacity in the GB Capacity Market and can be implemented in time for I-SEM go-live.

## 3.2 SECONDARY TRADING

We believe that efficient secondary trading arrangements are critical to the success of the CRM and that all the options consulted on could potentially be implementable for I-SEM go-live; however, were any of the options to be more complex and bespoke we would need to further assess this. Ultimately, the choice of secondary trading approach comes down to a balance between policy considerations and the commercial preferences of the current and future capacity providers. In keeping with the centralised nature of the I-SEM and the CRM, the mandatory centralised platform would be our preferred approach as we believe it would concentrate liquidity and provide a clear route to market for smaller player's and non-portfolio providers. In our view, only capacity providers that have qualified for the CRM should be able to trade Reliability Options and only up to their de-rated capacity. If the demand for secondary trading were to align with the volume of scheduled outages, we could potentially see more than 1000MW of trade in some of the summer months. Adding forced outages and potential changes to capacity providers' projects would add further liquidity. A standard trading approach e.g. simple auction, if implemented in conjunction with the primary auction, would represent a potentially efficient solution.

## 3.3 DETAILED RELIABILITY OPTION DESIGN

We believe that the product length should be aligned insofar as possible with the arrangements for DS3 system services. As stated in our response to CRM consultation 1, we do not believe stop-losses are necessary in the CRM. Stop losses essentially transfer the risk from the capacity provider to the suppliers (and end customers). We believe that units incurring uncovered difference charges on a regular basis have the opportunity to trade out of their reliability option to mitigate further losses due to non-performance. If stop losses are to be implemented we propose that they are implemented on an annual basis only and they be set at the highest level to ensure that the performance incentives inherent in the reliability option remain.

## 3.4 COMMISSIONING WINDOW AND IMPLEMENTATION AGREEMENTS

We would be interested in hearing current and future participants' views on the timelines discussed and the various checks involved regarding commissioning window and implementation agreements. Any performance bonds need to be considered in the context of the rules-based institutional arrangements. The level of performance bonds should be set to encourage providers to trade out of positions that they cannot physically back as early possible to avoid the need to draw down on any performance bond.

## 3.5 LEVEL OF ADMINISTERED SCARCITY PRICE

We have a number of suggestions on how to ensure that the correct signals emerge from the I-SEM when the system is experiencing scarcity. These are the times when the correct price signal from the balancing market to existing and new market participants to make themselves available to mitigate exposure to these events is critical. A reserve margin based on all available units leaves open the possibility that there are offline units that are available which cannot be synchronised in the timeframe necessary to avoid demand control. Rather than the price increasing gradually along the administered scarcity price function as we approach the need for demand control, the reserve margin would give no indication of the proximity to a demand control event and a price of the Full Administered Scarcity Price. Alternatively, if the reserve margin was based on actual operating or replacement reserve, e.g. Tertiary Operating Reserve II, the price would signal the imminence of a demand control event and encourage the strong response from capacity providers necessary to mitigate such an event.

## 3.6 TRANSITIONAL ISSUES

Finally, on the transitional arrangements, either the Annual Auction or the Block Auction would work in our view with a slight preference for the Annual Auction as it allows the opportunity to address any issues encountered in the previous year's auction. The third option of do-nothing is not an attractive option in our view as it would represent a significant disruption to the investment in capacity in Ireland and Northern Ireland. The implications of a gap in CRM funding will be highlighted in the 2016 – 2025 Generation Capacity Statement produced by SONI and EirGrid in response to a request from the RAs and Government Departments.

# 4 EIRGRID AND SONI VIEWS ON THE CONSULTATION TOPICS

## 4.1 INTERCONNECTOR AND CROSS-BORDER CAPACITY

### 4.1.1 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).

As an enduring approach to the treatment of cross-border capacity, EirGrid and SONI would favour a regional approach developed in the context of upcoming Energy Union decisions at a European level. We believe there are significant challenges in the development of participant-led approach and that these challenges would be best addressed at a regional level in cooperation with the relevant parties in our neighbouring markets (in particular GB). We believe that implementation of a provider-led solution prior to the development of a regional approach would be premature. In the interim, we would suggest that an interconnector-led approach offers a solution that is both consistent with the treatment of cross border capacity in the GB Capacity Market and can be implemented in time for I-SEM go-live.

Capacity market coupling at a regional level could be given effect in a similar manner to how the day-ahead market coupling is carried out today; however, some alignment of the products would be necessary. It should be noted that while the current DAM coupling takes place across Europe, the charges associated with non-delivery vary considerably across balancing arrangements. While the direction of travel is to align these balancing arrangements under the Network Code for Electricity Balancing, this alignment was not a prerequisite for market coupling. Similarly, quantity based annual capacity auctions could be coupled without full harmonisation of the charges for non delivery. Such an approach would not in our view be deliverable for I-SEM go-live but we believe a roadmap should be developed with the relevant parties in neighbouring markets that sets out a clear path to implementing such a solution.

We are strong advocates of a technology neutral CRM and that participation should be on the basis of a capacity provider's ability to meet the requirements of the mechanism. With this in mind, we believe that a regional solution based on a provider-led approach best satisfies this criterion. In contrast, Netting off, while attractive in terms of simplicity, unnecessarily treats cross border capacity participants in a fundamentally different way to other capacity providers. As such, we would not favour this approach.

We can see how the FTR led approach is an effort to create a formal link between the capacity provider and the I-SEM; however, the FTR does not represent a physical capacity right and it is not clear how this would provide the necessary assurance that the capacity provider is physically backed. In the context of an enduring regional provider-led solution, an FTR may represent an important hedging vehicle to manage the financial exposure between the I-SEM DAM, which represents a key reference market for the Reliability Option, and the capacity provider's local DAM e.g. the GB DAM, which is the market where the capacity provider is physically trading. Nonetheless, we do not believe that an FTR should be a requirement to qualify for the CRM. Whether a participant chooses to buy an FTR should be a commercial decision based on their trading strategy. We would also note that an FTR only provides a hedge between the DAM in the I-SEM and the DAM in GB. A capacity provider trading in the GB intraday and balancing arrangements would be exposed to the spread between the respective markets.

When deciding whether a performance based or an availability based approach should be adopted, we would suggest that a performance based approach is more consistent with the design of the Reliability Option where the entity involved has title to the energy output associated with the capacity. On the other hand, similar to the way market coupling currently operates where DA markets are coupled but delivery of energy is subject to local balancing arrangements, it may be the case that an initial regional solution couples the capacity auctions but leaves the assessment of performance and associated charges to the local capacity arrangements. In the context of any interim interconnector-led solution, consistency with the treatment of cross border arrangements in the neighbouring markets would be a potential first step towards a regional solution.

The Hybrid approaches indicate that the interconnector could in some way retain the spread between the capacity clearing prices in the I-SEM and GB and be exposed to difference payments to the extent that they are not available. We would suggest that this is the role of FTRs. As both the I-SEM and GB mechanisms represent the value of capacity in the respective markets and the value of capacity could be considered to be the option value on the physical energy price, the difference between the capacity prices represents the option value on the difference between the energy prices, which is essentially an FTR. As the allocation of FTRs is governed by the Harmonised Allocation Rules developed under the Network Code for Forward Capacity Allocation, it is not clear how the proposed Hybrid mechanism would sit with the rules required for forward capacity allocation. Further consideration of the implications of this approach on the options being considered by the Forwards and Liquidity workstream would be essential before the hybrid options could be progressed.

### 4.1.2 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?

As the energy flows will be determined by the spreads between the prices in the I-SEM and GB, it follows that the rational flow of energy should be from low price to high price and that the energy should flow into the I-SEM at times of scarcity on the basis that the price in I-SEM will signal this scarcity. This is the basis of the Reliability Option design. We would suggest that this should be basic assumption in relation to the future flows of energy. There are potentially times where the price in GB is higher than the I-SEM during an I-SEM scarcity period due to simultaneous scarcity period in GB. As such, it may be necessary to consider in the de-rating process the correlation of these events, the resultant scarcity prices that would arise and the extent that the outcome would align with the agreed process dealing with these events.

Due to ongoing energy and environmental policy developments, markets and generation portfolios in Europe are currently experiencing an extended period of significant change. Modelling of future interconnector flows and, in particular, accurately forecasting scarcity events under such conditions is very challenging. While it may be deemed that such modelling is the most suitable method to calculate de-ratings for interconnectors in the I-SEM CRM, it should be acknowledged that there will be an inherent uncertainty in such predictions.

## 4.2 SECONDARY TRADING

### 4.2.1 A) DO RESPONDENTS AGREE THAT DIRECT SECONDARY TRADING OF RELIABILITY OPTIONS SHOULD BE PERMITTED?

We believe that efficient secondary trading arrangements are crucial to the success of the CRM. Secondary trading enables participants to manage changes in their capacity delivery schedules, planned maintenance schedules, forced outages and so on and in doing so reduces the risks associated with selling a Reliability Options and hence any risk premia that may be present in the primary auction. Secondary trading also provides a means by which providers can manage any unforeseen losses e.g. arising out of a prolonged forced outage and reduces the need for stop loss limits.

Direct secondary trading would be our preferred option for secondary trading. As delivery body, we would understand our role to include maintenance of the reliability option register. This register would not only include parties to reliability options but also parties that have been qualified and are capable of taking on reliability options in secondary trading. It is important in our view that secondary trading does not provide a means to eliminate the need to have physical backing and that any participant that offers a reliability option has sufficient de-rated capacity to do so.

### 4.2.2 B) SHOULD SECONDARY TRADING OF RELIABILITY OPTIONS BE VIA AN ORGANISED SECONDARY PLATFORM? IF SO, WHICH ONE OF THE OPTIONS IS PREFERRED?

All the options consulted on are potentially implementable for I-SEM go-live provided a relatively standard approach is adopted. Ultimately, the choice of secondary trading options comes down to a balance between policy considerations and the commercial preferences of the current and future capacity providers; however, in keeping with the centralised nature of the I-SEM and the CRM, the mandatory centralised platform would be our preferred approach as we believe it would concentrate liquidity and provide a clear route to market for smaller player’s and non-portfolio providers. In our view, only capacity providers that have qualified for the CRM should be able to trade Reliability Options and only up to their de-rated capacity. If the demand for secondary trading were to align with the volume of scheduled generation outages, we could potentially see more than 1000MW of trade in some of the summer months. Adding forced outages and potential changes to capacity providers' projects would add further liquidity. A standard trading approach e.g. simple auction, if implemented in conjunction with the primary auction, would represent a potentially efficient solution; however, were any of the options to be more complex and bespoke we would need to further assess this.

### 4.2.3 C) DO RESPONDENTS BELIEVE THAT "BACK-TO-BACK" TRADING TO LAY-OFF EXPOSURE TO DIFFERENCE PAYMENTS SHOULD BE PERMITTED?

We believe that direct trading should be the only route to transfer Reliability Options between parties. Notwithstanding the above, we do not see how it would be possible to restrict providers from entering into financial hedge contracts.

### 4.2.4 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;

Yes. The max volume of scheduled outages in any week at times exceeds 1500MW for both 2016 and 2017. If forced outages, project delays etc. are added to this, it is likely that there will be sufficient demand.

### 4.2.5 D) WITH RESPECT TO THE CREATION OF A CENTRALISED RELIABILITY OPTION SECONDARY MARKET 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?

Units de-rated due to the probability of forced outage should not be allowed trade beyond their de-rated capacity as the likelihood of forced outage is no less reduced closer to real time.

There may be merit in considering allowing variable generator units to sell more reliability options if forecasts indicate that their availability is expected to be above average. This would need to be time limited in line with reasonable forecasting horizons.

### 4.2.6 D) WITH RESPECT TO THE CREATION OF A CENTRALISED RELIABILITY OPTION SECONDARY MARKET PLATFORM: 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?

Secondary trading could potentially occur through a simple centralised auction commencing after the primary auction. How frequent these auctions are or whether there should be continuous trading would depend on the likely demand and length of the product being traded in the secondary market.

#### 4.2.7 D) WITH RESPECT TO THE CREATION OF A CENTRALISED RELIABILITY OPTION SECONDARY MARKET PLATFORM: 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?

We believe that this desirable as it would make the arrangements more flexible and also distribute the workload associated with registering and qualifying capacity providers more evenly. This would also open up the possibility of synergies with other arrangements requiring qualification/registration e.g. DS3 system services.

#### 4.2.8 D) WITH RESPECT TO THE CREATION OF A CENTRALISED RELIABILITY OPTION SECONDARY MARKET PLATFORM: V. SHOULD A SECONDARY ACQUIRER OF A RELIABILITY OPTION START FROM A ZERO POSITION AGAINST EACH "STOP-LOSS" LIMIT, OR SHOULD THE LOSS TRANSFER?

The total level of uncovered difference charges in a period should be tracked at a capacity provider level. When a capacity provider trades reliability options in the secondary market, the total level of uncovered difference charges to date is unchanged and should continue to be tracked at the capacity provider level. What would change is the annual revenue to both capacity providers involved in the secondary trade and if the stop loss limit is a function of the total revenue due to that capacity provider in the period, it follows that the stop loss limit for that period would change with the secondary trade. It would be important to ensure that a capacity provider cannot claw back lost revenue by secondary trading out of their position and reducing their stop loss to below their uncovered difference charges.

## 4.3 DETAILED RELIABILITY OPTION DESIGN

### 4.3.1 A) PRINCIPLE OF LONGER TERM RELIABILITY OPTIONS:

##### 4.3.1.1 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?

Where significant investment is taking place for new or refurbished capacity, we believe there is an equal case for longer term reliability options. In this regard, alignment with the DS3 system service arrangements is an important consideration to ensure consistent signals to service providers.

### 4.3.2 B) CLASSIFICATION OF PLANT AS NEW, UPGRADE OR EXISTING

#### 4.3.2.1 I. DO RESPONDENTS HAVE A VIEW ON WHICH APPROACH SHOULD BE USED TO CLASSIFY CAPACITY PROVIDERS AS "NEW", "UPGRADE" OR "EXISTING"?

We would favour cost threshold and tangible facts as sufficient evidence of new or refurbished capacity over expert judgement as they provide clear criteria to existing and potential investors on what would qualify for a longer term contract.

The RAs would need to clarify what these cost thresholds and tangible facts are and how capacity providers can provide this information to the delivery body to qualify for any longer term products.

#### 4.3.2.2 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.

We would not favour unnecessarily segmenting capacity into new, upgrade and existing. This has the potential to introduce artificial limits and thresholds that may not reflect diversity of projects that may wish to enter into reliability options or may limit the efficiency of the outcome. Rather than considering whether a project is existing, an upgrade or new, it may be more suitable to look at the factors which differentiate these investments.

### 4.3.3 C) MAXIMUM AVAILABLE RELIABILITY OPTION LENGTHS

#### 4.3.3.1 I. DO RESPONDENTS HAVE A VIEW ON THE APPROPRIATE MAXIMUM RELIABILITY OPTION LENGTHS THAT SHOULD BE AVAILABLE TO NEW-BUILD AND UPGRADED PLANT?

Reliability Option lengths, where appropriate, should be aligned with the DS3 System Service agreement lengths.

## 4.4 STOP-LOSS LIMITS QUESTIONS

### 4.4.1 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?

In general, we believe that stop loss limits reduce the efficiency of the arrangements. The consultation paper refers to the absence of stop-loss limits possibly leading to capacity providers reflecting this risk in their offers; however, we believe that this is the role of the auction. As the risk to different capacity providers is not the same, all other things being equal, more reliable capacity providers can better manage this risk than less reliable capacity providers. As the reliability of the capacity provider is within the control of the capacity provider, placing the risk on to them should lead to a more efficient outcome as their improved performance will mitigate the instances of high prices in the balancing arrangements. We appreciate that there are implications for the cost of capital of capacity providers; however, stop-loss limits ultimately socialise the risk to suppliers, which is likely to be reflected in retail tariffs.

Stop-loss limits also add significant complexity to the balancing of the charges and payments. Where a stop-loss limit becomes active and limits any further difference charges to a capacity provider, this will result in a hole in the hedge that will need to be funded by the market.

We would see benefit in setting up the arrangements such that capacity providers who were experiencing high levels of uncovered difference charges use secondary trading to reduce a position that they cannot deliver against. Secondary trading would need to be reasonably liquid and frequent to enable capacity providers to be able adjust their position on a regular basis. On the basis of the levels of scheduled and forced outages that occur on the system, we believe that such volumes of secondary trading would be sufficient to support the trading out of a position to essentially give effect to a stop–loss limit without there being the need for an administratively set value.

We agree that the I-SEM capacity year should run from October to September. This ensures that physical capacity will be delivered prior to the winter season when capacity is generally of most value. If stop-loss limits are to be implemented, we believe that they should be annual at twice the annual revenue of the capacity provider.

### 4.4.2 E) DO RESPONDENTS BELIEVE THAT “PER EVENT/DAY” AND “PER MONTH” LIMITS ARE REQUIRED IN ADDITION TO THE ANNUAL STOP LOSS LIMIT?

We would only be in favour of per event/day/week/month stop loss limits if the limits were set sufficiently high to minimise the interference with the incentives inherent in the reliability option.

## 4.5 LEVEL OF ADMINISTERED SCARCITY PRICE

### 4.5.1 A) WHICH OF THE OPTIONS DO RESPONDENTS PREFER (AND WHY) FOR THE ENDURING LEVEL OF THE FULL ADMINISTERED SCARCITY PRICE (FASP)?

We believe an "EU consistent" approach to be the most suitable. Alignment with our neighbouring markets, in particular GB, is important to ensure that the right cross border signals prevail at times of system scarcity. In the unlikely event of simultaneous load shedding, the prices should be relatively aligned (notwithstanding currency considerations) and the actions taken by the TSOs should reflect the agreed processes for simultaneous load shedding events. Where a demand control event is occurring in one of the markets, the price in the other market should be lower resulting in the signal to flow energy into the market where the load shedding is occurring.

### 4.5.2 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.

The exact definition of a demand control event needs to be carefully aligned with the current Grid Code arrangements for such events and also needs to have due consideration for the draft Network Codes on Operational Security and Load Frequency Control and Reserve. In our view, the event needs to be clearly and unambiguously defined to ensure that there is no subjectivity in what does and does not constitute a demand control event.

#### 4.5.2.1 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)?

We agree that the definition should be based on actions taken consistent with the principle that imbalance pricing should be based on actions taken by the TSOs.

#### 4.5.2.2 HOW FAR SHOULD VOLTAGE FALL BEFORE FULL LOAD SHEDDING IS JUDGED TO HAVE OCCURRED?

This should be defined in the market rules to align with the relevant sections of the Grid Codes and should have consideration for draft Network Code on Operational Security.

#### 4.5.2.3 HOW FAR SHOULD FREQUENCY FALL BEFORE FULL LOAD SHEDDING IS JUDGED TO HAVE OCCURRED?

This should be defined in the market rules to align with the relevant sections of the Grid Codes and should have consideration for draft Network Code on Load Frequency Control and Reserve.

### 4.5.2.4 FOR HOW LONG SHOULD ANY DROP IN VOLTAGE OR FREQUENCY BE SUSTAINED BEFORE FULL LOAD SHEDDING IS JUDGED TO HAVE OCCURRED?

This should be defined in the market rules to align with the relevant sections of the Grid Codes and should have consideration for draft Network Code on Load Frequency Control and Reserve.

### 4.5.3 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.

We do not have a strong view on this; however, we believe that the levels of the ASP need to be reasonably known for all years being considered in the auction as the value of the reliability options is linked to the this price. As it may be necessary from time to time to consider changes to the ASP to reflect prevailing market conditions and to ensure consistent prices between other balancing arrangements, the arrangements need to allow for reasonable changes to the ASP.

### 4.5.4 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.

We believe that an “EU consistent” FASP is the best approach, which would require changing the FASP in line with the proposed changes in GB.

### 4.5.5 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?

There needs to be consistency between the reduced operating reserve definition and load shedding. The consultation defines the former as a static measure of margin (i.e. it is based on available capacity less demand) whereas the latter is a dynamic measure of margin (available *online* capacity being less than demand). This could lead to outcomes where the operating reserve, as defined in the consultation paper, is greater than zero and load shedding has occurred. This is due to the fact that the system operator cannot access offline units in time to balance the system.

For example, if a large unit with a notification time of several hours is offline in a cold state, once the notification time has passed, the TSOs cannot access this unit. If the system margin is low such that the online capacity is not sufficient to meet the required levels of operating reserves, the TSO will need to activate operating reserves in order to meet the demand. In these instances, the price will remain relatively benign based on the prices of the actions taken on units carrying operating reserves.

If this capacity is not sufficient and demand control is initiated, the price will go from a fairly benign price to full ASP. In this instance, the lack of reserve scarcity prices prior to demand control could create situations where demand control is required. As the price prior to demand control would be relatively low, there is no incentive for demand to voluntarily reduce and no incentive for larger offline units to get a position in the day ahead and intraday markets to be available for balancing actions (and potentially system service payments). The risk of demand control may provide this incentive; however, in our view the price should move up along the reserve scarcity curve as the capacity available to the TSO approaches the demand.

If this were the case, in the above scenario, as soon as the TSOs begin to reduce operating reserves below the required level, the price would increase towards the full ASP in line with the LOLP curve. This would provide clear signals to demand to voluntarily reduce and to encourage offline units to part load earlier in order to mitigate exposure to demand control events. Placing a greater value on activated operating reserve capacity in line with the increase in LOLP that would occur as operating reserves are reduced below required levels would prevent these reserves being used except as a last resort before demand control.

This is the approach taken in GB where reserve scarcity pricing is triggered by activation of STOR contracts. In line with previous comments, we believe that as the policies in relation to scarcity pricing are similar, we believe there is merit in aligning our approach with the approach adopted in GB.

## 4.6 TRANSITIONAL ISSUES

### 4.6.1 A) WHICH OF THE SUGGESTED OPTIONS (ANNUAL AUCTION, BLOCK AUCTION, DO NOTHING) DO YOU PREFER?

Either the Annual Auction or the Block Auction would work in our view with a slight preference for the Annual Auction as it allows the opportunity to address any issues encountered in the previous year's auction. The third option of do-nothing is not an attractive option in our view as it would represent a significant disruption to the investment in capacity in Ireland and Northern Ireland. The implications of a gap in CRM funding will be highlighted in the 2016 – 2025 Generation Capacity Statement produced by SONI and EirGrid in response to a request from the RAs and Government Departments.