Integrated Single Electricity Market (I-SEM)

Capacity Remuneration Mechanism

Consultation Paper

SEM-15-044

Power NI Response

17 August 2015

Introduction

Power NI welcomes the opportunity to respond to the Regulatory Authorities (RAs) Capacity Remuneration Mechanism (CRM) Detailed Design Consultation Paper.

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

Power NI is however a separate business. Power NI's legal, managerial and operational separation is mandated via licence condition and it is within the context of being a supplier without vertical integration; that Power NI has approached the CRM workshops, assessed the issues presented and now responds to the CRM Detailed Design Consultation Paper.

General Comments

In our response to the RAs draft high level design decision (SEM-14-045) Power NI stated –

> *"Power NI welcomes the RAs decision to include a CRM in the I-SEM. The current SEM CRM provides a significant income stream for generating participants. From a supplier perspective it is important to recognise that a CRM does provide important investment signals for generation capacity provision and can dampen energy price volatility which would occur in an energy only market."*

Power NI remains of the view that a CRM is required. The RAs proposal is however highly complex and Power NI has real concerns in relation to potential unintended consequences. To assist with the assessment Viridian commissioned a report by NERA. Power NI has included a copy of the report in Appendix 1 for the RAs consideration.

As stated by NERA, Power NI would also welcome extensive further engagement with the RAs in relation to the CRM design. The ISEM project is particularly complex and with a number of workstreams progressing in parallel there is a risk of design inconsistencies and a sub-optimal outcome. The CRM is a crucial element of the ISEM design and will have impacts on and be impacted by the energy trading, forwards, market power and DS3 workstreams.

When considering the CRM design Power NI believes careful consideration is required of the potential impacts it could have on the Forwards Market (FM). There is a need for a strong focus on the development of a liquid FM in I-SEM as the majority of customers, whether domestic or commercial, require energy tariffs with price certainty to insulate themselves from volatility in wholesale energy markets; and ultimately, as consumers pay for the energy market, they should have the choice of a fixed tariff if they desire it. As a non-vertically integrated supplier with a customer base largely on regulated tariffs, Power NI is entirely dependent on forward liquidity to manage risk and deliver price stability for customers.

A liquid and transparent FM should enable suppliers to hedge efficiently, shield consumers from volatile spot markets and offer consumers competition and innovation in tariff structures. FMs should also provide open access to mitigate market power and generate price signals to drive investment. It is crucial therefore that there is a fully functional and liquid FM in the I-SEM.

The FM in the current SEM suffers from a number of significant deficiencies, some of which are highlighted in the discussion paper. Power NI considers the key issues include:

- Lack of available volume
- Infrequency of trading opportunities
- Lack of transparency
- Small market with concentrated number of players and market dominance
- Inexplicable price spreads
- Scarcity premiums
- Lack of non-physical traders
- No real benchmark forward curve

There are a number of factors which influence the lack of liquidity in SEM which are factors in the I-SEM High Level Design, and hence are likely to continue to cause similar issues to those stated above. The delivery of liquidity in the DAM to facilitate effective market coupling will not in itself deliver a liquid FM (as evidenced by the GB experience).

The proposed Reliability Options (ROs) are highly complex and their interaction with the FM needs to be fully understood, and whether the obligations on generators involved in this mechanism will place further risks on them and make it less likely that they will actively sell CfDs. The design of the CRM product therefore requires careful consideration especially in relation to the effect they may have on FM products and liquidity. This area is of fundamental concern to suppliers.

Capacity Requirement

- **Security Standard**

The Loss of Load Expectation (LoLE) is an important policy consideration for the entire market. Power NI is somewhat concerned that this key policy area is being debated within the capacity workstream and is not a set value determined and reviewed by the Regulatory Authorities in conjunction with the Departments in a clear and transparent public manner. The CRM should be designed to input this figure into the necessary calculations and should not be the forum to debate the value.

Furthermore the current position appears disjointed and Power NI assumes this manifests itself in a cost to consumers of having differing standards within the SEM i.e. SEM: 8 hours LoLE, Ireland: 8 hours LoLE and Northern Ireland: 4.9 hours LoLE.

Instinctively any reduction from the SEM 8 hour LoLE and the accompanying cost implications are of concern. Power NI however would welcome further robust analysis undertaken by the SEM Committee to investigate the actual current applicable standard as well as a valuation of reliability in today's market. This would include analysis of the process of converting a standard to a MW requirement under any support mechanism and ensuring that it is only the standard that consumers pay for.

- **Accounting for plant unreliability**

As discussed within the Eligibility Section of this paper, Power NI supports a de-rating methodology. The de-rating approach must be designed to forecast predicted plant contribution at times of system stress.

- **Zonal Consideration**

Given the I-SEM is inherently an all-island market and energy is to be treated as one zone Power NI supports the consideration of capacity as one zone.

- **Accounting for demand forecast uncertainty**

Similar to the discussion in relation to LoLE, Power NI is somewhat surprised that the demand forecasting methodology is being debated within the CRM workstream.

TSO demand forecasting is an important function of the market and will have impacts in both the energy trading and DS3 areas and Power NI would urge a consistent and transparent approach to be adopted. Approaching forecasting in a piecemeal manner risks implementation inconsistency.

Product Design

The introduction of the ROs, as highlighted within the consultation paper, will have a significant bearing on hedging products offered in the energy market. As stated above, effective FM liquidity is a vital aspect of the market design. The ability of suppliers to effectively hedge energy costs has a direct impact on end customers, who ultimately pay for all market costs.

Even in the SEM, the FM is characterised by a scarcity and lack of liquidity and it is imperative that this is properly addressed in the I-SEM. Hence, appropriate assessment of the consequences of the RO mechanism on the FM is essential for end consumers.

The proposed RO will require a fundamental revision to FM products, with implications for risk management. Particular concerns from a supplier perspective would therefore include:

- The impact, whether positive or negative, on the volume of CfDs offered to the market as a result of changes to accommodate the RO;
- The effectiveness of energy volumes hedged using CfDs, in particular where the RO mechanism references floating strike prices and such prices may change over time;
- The effectiveness of the RO as a hedge for periods where the energy price exceeds the RO strike price; and
- The effectiveness of the RO in managing price risk in periods of scarcity, in the event that sufficient CfDs were not available.

As previously stated, this interaction between the RO and CfDs is a fundamental concern for suppliers. Even if it were possible to have an effective FM, such that the full forecast energy volume could be hedged via CfDs, it is vitally important that the interaction between the RO and CfDs would not significantly impair the effectiveness of the hedge as a whole.

In particular, Power NI feels that it is imperative that any difference payments by the RO holder are redistributed to suppliers in a timely manner and on the basis of suppliers' actual half-hourly consumption for the periods in question. Were any difference payments from the RO holder to be held centrally and absorbed in aggregate as a “k factor” into a future capacity tariff, there could be substantial cash-flow and accounting issues for suppliers. In reality, suppliers would incur the full energy cost, but where hedged with forward contracts, in the first instance would receive difference payments to the level of the RO strike price. If the difference payment made by the RO holder were not to flow back to suppliers on a timely basis, the result would be a cash shortfall and potentially a net loss would be recognised in the financial statements, completely undermining the purpose in hedging energy costs in the first place.

The interaction between the RO and CfDs is a serious matter for suppliers as it would seem to introduce further basis risk, impacting on the risk management activities required. In Power NI's view, a "floating" strike price could add further complexity to the risk management process. Moreover, having the RO covered by a wide range of strike prices may also have serious implications for the FM in terms of complexity and liquidity.

Setting an appropriate level for the strike price is a key consideration. As outlined in the consultation paper, ensuring that difference payments are only made when all available capacity is required is essential.

- **Scarcity Pricing**

As with GB, scarcity pricing may be appropriate in providing an additional performance incentive mechanism, and indeed the BNE approach to an administered scarcity price may seem a reasonable approach and is consistent with the current SEM. However, Power NI would have expected the issue to be considered within the balancing market as part of the ETA workstream.

- **Market Reference Price**

Whilst the Balancing Market may better reflect real-time system stress than the other options, Power NI has concerns over the consequential impact that focusing the RO on the balancing market may bring. In particular, the potential impact on Day Ahead Market liquidity is again of key importance for suppliers, as without this a well-functioning FM will be impossible. An effective DAM should also aid effective interconnector and Euphemia scheduling. As outlined in the consultation paper, this could frustrate one of the key objectives of the I-SEM.

As FM CfDs will almost certainly be referenced to the DAM, choosing a different RO reference price would exacerbate the basis risk faced by suppliers even further.

A multiple reference price approach has the attraction that it could potentially balance the requirements of maintaining a strong FM with the short-term signalling of system-stress. However, Power NI has concerns that having multiple reference prices could be very complex and difficult to appropriately design before understanding the volume of energy traded in the DAM vs BM etc.

- **Load Following Obligations**

The load following obligation would seem to be an appropriate approach as otherwise volumes in the RO could lead to over-hedging, therefore resulting in a higher RO price required by generators in the first place.

A key consideration will be the levels of generation outside of the RO mechanism, as this again risks distorting the effectiveness of the difference payment mechanism of the RO in hedging excess costs in the market. In particular, the level of wind outside of the RO mechanism could be an issue going forward, given the level of non-predictable renewables in the market.

- **Physical Performance Incentives**

Physical performance incentives are clearly a very important component of the RO mechanism in delivering actual capacity at times of system stress. Whilst Power NI would support a performance incentive mechanism, it is very important that such incentives are applicable only in periods of system stress.

Additionally, Power NI feels that the use of caps / floors on incentives represent an appropriate control for the practical application of performance incentives in delivering an effective outcome for the market at large.

Eligibility

As a general principle and starting point for eligibility, the ROs should be eligible to all with no special treatment, exclusions or preferential terms. Special rules, for example to cater for market power or other policy issues will have to be adopted; however, they must be incorporated in a manner that doesn't compromise the overarching objectives of the scheme or the fundamental principles that should underpin decision making[1] associated with it.

The HLD states that resources issued with ROs "*must be backed up by a physical resource that is capable of providing the capacity when required*." The ability to contribute capacity at times of system stress must therefore be the key consideration when establishing eligibility criteria. This ability to provide capacity when required should be underpinned by performance incentives that effectively 'self-police' participation. As recommended by Peter Cramton[2], whilst referring to the '4 P's' of a successful design, performance is by far the most important, with the others being planning product and pricing.

A key consideration in the consultation paper is whether plant, either renewable or thermal receiving support under other mechanisms should be eligible for ROs. This existing support ranges from PSO backed generation in both jurisdictions to different low carbon / renewable schemes in Ireland and Northern Ireland. In keeping with the non-discriminatory nature on which the RO scheme should be developed, it is Power NI's view that all supported generators should be eligible for ROs.

If all generators are eligible for the ROs the question of mandated versus voluntary participation has to be addressed. Mandated participation should ensure that the volume of ROs are close to system load at all times, including

[1] Efficiency, transparency, fairness, and simplicity should be at the forefront of decision making
[2] At capacity market fundamentals industry workshop in Dundalk on 08 May 2015

times of system stress. If however, intermittent generators are subject to the same performance incentives as dispatchable generators, as should be the case, it would seem unfair to mandate their participation. A potential solution to this would therefore be to mandate participation for dispatchable plant and make participation voluntary for intermittent generators.

A potential downside to this approach might be the availability of the volume of RO supported generation at times of system stress. That being said, with high levels of intermittent generation in the Irish market there is a high likelihood system stress will occur at times when intermittent generation is not available.

Consideration also has to be given to the role of Demand Side Units (DSUs) and their eligibility for the RO mechanism. In principle, as with generation, either dispatchable or intermittent, if they can contribute at times of system stress they should be eligible to participate. In establishing criteria around DSU participation, attention must be paid to ensure their 'true' contribution at times of system stress is recognised and it is this volume eligible for an RO and that the cost of a DSU RO is in-line with that of an RO with any other holder i.e. no special treatment.

- **De-Rating**

The HLD position states that ROs must be physically backed representing an RO holders' ability to deliver capacity at times of system stress. For this reason, Power NI believes 'de-rated' rather than 'nameplate' capacity would appear a more appropriate reference against which RO volumes should be issued, on the assumption the de-rated volume is designed to represent a resources contribution to supply at times of system stress.

Given the overarching principle that ROs must be physically backed it would seem appropriate that specific plant de-rating factors are calculated and adopted in respect of dispatchable generation. By definition using technology specific average factors would result in some plants being unable to meet their de-rated volumes if they are below the average. On the flip side plants that perform above the average would be prevented from realising their true contribution potential. Optimal performance should be rewarded and act as an incentive to others. Alternatively 'one size fits all' will ultimately result in one size fitting nobody.

As a follow on to this point it would also appear logical that historic performance is used as the benchmark when determining de-rating factors. Consideration will need to be given to the historic time horizon used to ensure it is reflective and indicative of the period the RO will be covering. De-rating factors for new generators could be linked to plants of similar characteristics until sufficient history is available.

Consideration will also have to be given to generation with non-firm transmission access. In general, if these generators are able to contribute at times of system stress they should be eligible to participate in the scheme. In keeping with above the de-rating factors should be calculated on a plant specific basis, recognising the likely contribution of that plant, cognisant of their constraint, at times of system stress. These de-rating factors will have to be reviewed as the transmission landscape changes over time.

With respect to intermittent generation, in particular wind, consideration should be given to building digression levels into the de-rating factors over time. As wind levels increase the likelihood of system stress events being caused by low wind generation also increases, reducing the ability for wind to contribute when required. It would seem reasonable to take account of this when setting de-rating factors for wind, reflecting forecast wind deployment levels over the RO horizon.

If wind resources do not participate in the scheme, for example due to non-mandating of intermittent generation or prohibitive performance incentives / penalties, the overall capacity requirement needs to be adjusted to reflect the potential de-rated contribution of these resources. The above point with regards to digression should also apply in this instance.

Supplier Arrangements

Any wholesale CRM is of particular importance to suppliers. Instinctively CRM's such as the current SEM version are principally relevant to suppliers in securing generation adequacy and are practically important due to the payment (cash flow) and collateral requirements.

The RAs proposed I-SEM CRM is additionally pertinent to suppliers due to the potential impacts it could have on the FM.

As discussed previously, the FM is vitally important to the proper functioning of the I-SEM. There must be a strong focus on the development of a liquid forward market in I-SEM as the majority of customers, whether domestic or commercial, require energy tariffs with price certainty to insulate themselves from volatility in wholesale energy markets; and ultimately, as consumers pay for the energy market, they should have the choice of a fixed tariff if they desire it. As a non-vertically integrated supplier with a customer base largely on regulated tariffs, Power NI is entirely dependent on forward liquidity to manage risk and deliver price stability for customers.

A liquid and transparent forward market should enable suppliers to hedge efficiently, shield consumers from volatile spot markets and offer consumers competition and innovation in tariff structures. Forward markets should also provide open access to mitigate market power and generate price signals to drive investment. It is crucial therefore that there is a fully functional and liquid FM in the ISEM.

To the extent therefore that the proposed I-SEM CRM adversely impacts either the liquidity or the effectiveness of the hedges available in the FM represents a key concern for suppliers.

In considering the features of the CRM described, the flows of money fall into two categories from a supplier perspective. Flow one relates to supplier payments ‘out’ or effectively the money required to pay option fees. The second category relates to the money paid by generators. From the supplier perspective difference payments or penalties can be considered jointly as supplier payments ‘in’.

Power NI has considered each of these different payment types.

- **Supplier Payments “out” – Option Payments**

The RAs have identified the sums required to meet the option payment obligations as being largely predictable. In determining the methodology to recover this amount from suppliers the RAs have proposed using a suppliers’ total demand and a capacity price.

In setting the price, Power NI recommends that the RAs adopt a methodology consistent with today’s SEM CRM.

A flat charge is an inequitable burden on those customers with a shaped demand and the GB-esk option contains inherent flaws as it also inequitably accounts on the retail billing side, for potential peaks outside the November to February timeframe which are possible due to unexpected cold weather or outages.

Power NI believes that the current methodology which profiles cost across all hours provides the most equitable solution. Improvements could be made to the profiling however this does not detract from the policy decision which should be to endorse the current SEM approach.

In relation to the invoicing of the capacity options amount, while to a certain extent the settlement of the Day Ahead and Intra-Day markets will be driven by coupling arrangements; in general terms suppliers strong preference is for longer payment terms. This assists in managing the significant working capital requirements the wholesale market creates. The resultant reduction in credit exposure from any shortened payment terms is not a like for like balance. Power NI would therefore recommend that capacity option payments are invoiced to suppliers monthly, consistent with today’s SEM policy.

In determining the settlement processes, one central clearing body operating across all markets (including forwards & capacity) would facilitate the necessary netting arrangements which must be retained. The current SEM affords a settlement reallocation process which acts to reduce unnecessary working capital and credit exposure. This reduces participation costs and therefore ultimately cost to consumers. While the current settlement reallocation process may not naturally be able to transfer, the principle should endure. A contractual arrangement to reallocate a fixed percentage for example, may be a workable alternative.

- **Supplier Payments “in” – Difference Payments**

In relation to payments made by generators the RAs have posed the question as to how the returned funds should be administered.

Two options are presented in Section 5.5.13 of the paper. Power NI strongly believes that paid monies should be returned directly to suppliers based upon their demand proportion at the time the payment arose. To do otherwise would completely undermine the effectiveness of any Forward Market 2-Way Contract for Difference the supplier has secured and could render the Forward Market ineffective as a retail hedging methodology.

In effect when a supplier needs the hedge the most it would be ineffective. Suppliers will attempt to hedge their particular demand shape and to return monies on a basis other than the affected period risks undermining some hedges while over rewarding others.

Power NI concurs with the suggestion made in Section 5.5.15 to redistribute any surplus as a discount to subsequent option fees.

- **Credit Risk Requirements**

The current SEM principle in relation to credit cover is that the market should be fully collateralised. While this is a principle that participants supported, the implementation has resulted in a significantly over collateralised market. Power NI urges the RAs to consider all options to reduce the burden of collateral which is placed upon participants. This should include consideration of the forward market collateral requirements. A holistic approach to exposure, including provisions for netting or general reduction should be considered wherever possible. The RAs should also consider collateral options such as Parent Company Guarantees and insurances as alternatives to the cash or Letter of Credit approaches. Such options may provide a lower cost alternative while still providing the desired cover.

Power NI also agrees that generators should provide credit cover in relation to any difference payments due to the market. While agreeing with Section 5.6.5 that the requirement should relate to the net payment, it is unclear why the distinction is made in this paragraph between generators and suppliers. Power NI believes that supplier exposure should also be net otherwise you risk over collateralisation which is an unnecessary cost to participants and ultimately consumers.

- **Exchange Rate Risk**

While the exchange rate risk may be greater in the I-SEM in comparison to the SEM, Power NI sees little justification in changing the manner in which it is managed i.e. borne by the market in a socialised manner.

The risk identified as being placed on the central counterparty (Section 5.7.8) can be managed as in the current CRM and Power NI expects that in a small market such as the I-SEM the Capacity Market Operator will fulfil a number of additional roles and in all likelihood be subject to a price control or equivalent.

- **Section 5 Questions**

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

Power NI believes that the current methodology which profiles cost across all hours provides the most equitable solution and is consistent with the current policy.

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

Power NI believes suppliers' credit cover arrangement should be broadly similar to those under the SEM. An equivalent of settlement reallocations must be included and generators should be required to post collateral based upon their net exposure.

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

Power NI believes the costs of exchange rate variations should be mutualised across the market.

Institutional Framework

In identifying the roles and responsibilities for administering the CRM the RAs have proposed a number of delivery functions which the TSOs should undertake. These roles are consistent with other markets and appear to be a natural fit within the broader TSO function.

Power NI has previously supported the proposal that the operator responsible for the Balance Market settlement should also be responsible for the settlement of the CPM. Power NI remains of that view. There will be clear operational efficiencies from an entity using the metered load volumes for two purposes. Utilising more than one entity would require multiple interfaces for participants and should queries be raised it would reduce the administrative burden and general complexity by having to only raise the query with one body.

Power NI is concerned that although the RAs have begun the NEMO designation process this does not holistically cover the multitude of roles required within the I-SEM design. The ETA consultation is also silent on the role fulfilment question. Power NI would welcome the RAs considering this important design aspect and ensuring that it is included in the ETA decision making process.

As stated previously Power NI believes that there are synergies available by having a single entity fulfilling multiple roles, there must however be consideration given to appropriate ring fencing and governance provisions.

Conflicts of interest are most apparent when commercial incentives are in play. The current arrangements have the TSO in the role of system operator, market operator and asset (EWIC) owner. The I-SEM considerations could potentially widen the roles to DS3 auction operator, Capacity Administrator and Aggregator.

The concern is that the TSO would in effect be hosting an auction (for both capacity and ancillary services) which they could also be competing in or have a commercial interest in the design and outcomes from. They would also be operating a market in which they would be actively competing against other entities who are not the system or market operator. Power NI believes the conflict of EWIC ownership is an important area for the RAs to actively consider across a number of workstreams and not limited to one. Conflicts in relation to the role of TSO and Market Operator can be resolved in a manner consistent with today.

In relation to the framework of rules and codes, Power NI believes transparency and clarity will be enhanced by codifying the rules into the Trading and Settlement Code (or ISEM equivalent). This will ensure all participants and potential new entrants have full visibility of the CRM and its operational framework.

Additionally, it will provide an open and transparent methodology for the proposal of any future changes via the Modifications Committee or I-SEM equivalent.

Appendix A – NERA Report

NERA
ECONOMIC CONSULTING

The Capacity Remuneration Mechanism in the I-SEM – Detailed Design

Prepared for Viridian

14 August 2015

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Contents

1. Introduction

On 2 July 2015 the SEM Committee released a consultation (the "SEM Consultation") on the Detailed Design of the Capacity Remuneration Mechanism in the Integrated SEM (I-SEM).[1] The SEM Consultation provided a detailed outline of the Regulatory Authorities' perspective on the full range of design issues.

1.1. Our Instructions

Viridian has asked us to focus on three topics when addressing the RAs' proposed detailed design of the capacity market mechanism. These three topics are:

- setting strike prices and the Market Reference Price;
- capacity obligations; and
- penalties and enforcement.

We have addressed these topics by:

- reviewing the proposed arrangements for the design of these key elements of the scheme;
- providing input on the economic rationale behind the scheme design; and
- highlighting any trade-offs between objectives, to inform finalisation of the design.

We conclude with some suggestions for organising the next stage of design work on the CRM.

1.2. Summary of Findings

The RAs have chosen Reliability Options (ROs) as the high-level design for the capacity mechanism in the I-SEM. Holders of ROs will have to pay the difference between the market reference price and the strike price to the system operator whenever the market reference price rises above the strike price. In the next stage of design work on the capacity market, the RAs will select the strike price and reference prices for the RO contracts.

In this consultation, the RAs are soliciting advice on several features of the ROs. We have considered a number of aspects of RO design and our conclusions are as follows.

- **Level of strike price (chapter 2)**

The risks surrounding the selection of the RO strike price are asymmetric. In principle, a range of different strike prices would offer some additional incentive to provide capacity. However, practical considerations point towards setting a strike price towards the higher end of the feasible range. The lower the strike price, the more often holders of ROs will pay money to the system operator, the more valuable ROs will be, and the greater the proportion

1 I-SEM – Capacity Remuneration Mechanism Detailed Design (2015), Consultation Paper, SEM Committee, SEM 15-044, 5 July 2015.

of market participants' revenues will pass through the capacity market, rather than the energy market. Many aspects of the method used to recycle revenues from holders of capacity to supply businesses create unhedgeable risks for participants, and ultimately costs for consumers, with no offsetting benefit in additional security of supply. All other things being equal, the lower the strike price, the larger the volume of capacity holders' remuneration flowing through the capacity market, and the larger the unnecessary risks and costs that will ultimately be borne by consumers. ISO-NE is proposing to eliminate the Peak Energy Rent adjustment from its CRM, due to its poor performance as a hedge for Loads and the fact that hedging can be provided adequately by other means. This change would eliminate the problem for generators identified here.

- **Choice of Market Reference Price (chapter 2)**

The Market Reference Price (MRP) used to settle ROs must be taken from a "reference market". The choice of this reference market does not materially affect the incentives for delivery of energy (or capacity) during scarcity events: irrespective of the Market Reference Price chosen, and regardless how many ROs or Contracts for Difference (CFDs) each market participant holds, the incentive (i.e. the additional revenue) for providing additional output in real time is the Balancing Market price. However, the selection of Market Reference Price will drive trading and contracting behaviour. Traders will seek to minimise their exposure to basis risk and therefore have an incentive to trade physical output at the MRP and to sign CFDs settled against the MRP, which has important implications for competition and liquidity.

Market participants will shift trade into the relevant reference market as a way to eliminate basis risk. If I-SEM rules direct market participants to trade in markets other than the reference market, they will need to find (and be allowed to adopt) methods to mitigate that risk. For instance, the use of "virtual bids" would allow market participants to pass electricity right through the directed market and into the reference market; however, this solution may give rise to other potential problems, such as creating opportunities for manipulating market prices.

Taking the MRP from the Balancing Market would align all prices and risks, but would cause trade to focus on the BM and to shift away from the Day-Ahead Market. That might harm the liquidity of cross-border market coupling. Forcing market participants to trade in the DAM would create basis risk unless either the MRP was taken from the DAM or the MRP was taken from the BM and market participants could use virtual bids to transfer electricity from the DAM to the BM. The Intra-Day Market will not be liquid enough to provide a relevant MRP. Mixed schemes for defining the MRP bring additional complexity into the settlement of ROs and CFDs. As such, they increase the difficulty of hedging whilst offering little if any reduction in the exposure to basis risk.

- **Regulatory objectives, as applied to CRM design principles (chapter 3)**

The principles of adaptability and stability promote economic efficiency by reducing uncertainty for market participants. Market participants are able to make more efficient decisions when they can predict future the market outcomes and the future of the market mechanism itself. The CRM will achieve more efficient outcomes if the RAs develop formulae or conceptual frameworks to reduce scope for regulatory discretion and provide greater certainty to market participants.

For example, to maximise transparency and efficiency, the RAs should specify formulae that define how the capacity requirement is calculated and how de-rating factors for new and existing plants will be measured; as far as possible, these formulae should use observable public data (i.e. historical data, not someone's forecasts). For the sake of adaptability and stability, such rules should as far as possible be unrelated to specific technologies (which may change in future), but should use instead plant-specific data.

- **Rewards, penalties and efficient risk mitigation (chapter 4)**

Rewards and penalties based on performance during times of system stress are the fundamental drivers than ensure the CRM solves the "missing money" problem. RO settlement gives capacity providers no additional incentive other than the market price, so they may lack the incentive to provide sufficient capacity. In such circumstances, CRMs must be bolstered by additional penalties and rewards for providing more or less physical capacity during periods of system stress.

These rewards and penalties need to be targeted to encourage efficient decisions without creating unnecessary risks. The availability of any capacity may be affected by both internal and external factors – i.e. factors that are within the control of the plant operators (like maintenance) and factors that are outside their control (like the level of wind). When availability depends on external factors, then imposing penalties on capacity providers offers no additional incentive, whilst the additional risk of penalties outside their control discourages capacity providers from building capacity and participating in the scheme.

For instance, many CRM schemes put a cap on total penalties over short periods, to limit their financial impact on capacity providers. Such caps mitigate the risk of bankruptcy, particularly for unmanageable external risks that market participants cannot unwind through offsetting hedges. By doing so, they help to encourage participation in the CRM and hence to produce a more efficient outcome overall.

Thus, where it is impossible to distinguish clearly between the effects internal and external factors on output, the most *efficient* schemes offer a trade-off between incentives and risk mitigation (even if incentives are *muted* as a result).

- **Next steps**

The design of the CRM would benefit from industry input:

- on the implications of particular strike prices and MRPs for risk and liquidity, organised as a **workstream on pricing**;
- on the technical and plant-level data to be used in CRM formulae, organised as a **workstream on capacity definitions**; and
- on the economic and financial parameters used to define and limit rewards and penalties for providing capacity, organised as a **workstream on enforcement**.

1.3. The Structure of this Report

This report proceeds as follows:

- Chapter 2 assesses the potential methods of determining the strike price for a Reliability Obligation contract and of setting the Market Reference Price;
- Chapter 3 discusses how to define capacity obligations, including the capacity requirement, de-rating factors and load following obligations.
- Chapter 4 discusses the economic principles behind enforcement and incentivising capacity provision through penalties.

The report also includes the following appendices:

- Appendix A provides a short case study of the Italian Capacity Market Mechanism with a focus on the approach to setting the Market Reference Price.
- Appendix B provides a short case study of the ISO New England Market with a focus on the pay-for-performance scheme (proposed in conjunction with the removal of the Peak Energy Rent adjustment) scheme and the treatment of intermittent generation.
- Appendix C is a technical appendix on the incentives created by the blended approach to setting the Market Reference Price.
- Appendix D provides a formal description of the financial flows under the RO and the implications of a scenario where trading and RO settlement occur in different markets.

2. Strike and Market Reference Prices

This chapter outlines the economic rationale behind various approaches to setting the strike price and the Market Reference Price (MRP) and highlights the key trade-offs between objectives inherent in the choice of approach.

The chapter first sets out considerations for setting the strike price. This is followed by a detailed outline of the appropriate criteria for setting a MRP. The last four sections assess options for the MRP against these criteria. The four options are:

- Balancing market;
- Intra-day market;
- Day-ahead market; and
- Mixed schemes.

2.1. Setting the Reliability Obligation Strike Price

The strike price sets the level at which the TSO can call the RO option. It acts as a cap on the revenue received from the spot market for capacity covered by an RO contract.

The mechanism by which the strike price is set determines when and how often the RO is called, and hence how the risk of entering into a RO contract is allocated and shared among market participants. Below, we explore the ways in which the strike price affects the risk of participating in the RO:

- the absolute level of strike price and the extent to which this reflects the costs of capacity from the marginal plant;
- the implications of setting multiple strike prices; and
- the method of adjusting the strike price over time to account for changes in the underlying costs of the marginal plant.

2.1.1. Setting the level of the strike price

In principle, the strike price of the ROs limits consumers' exposure to high energy prices, but the strike price is not only determined by consumers' dislike of occasional price spikes. An equally important objective for the ROs is to reduce the risk facing generators and to encourage more investment in capacity, compared with a market where incentives and rewards depend on peak energy prices alone.

If the strike price is set too high, for instance near to the Value Of Lost Load (VOLL), investors in capacity remain dependent on (and consumers remain exposed to) the risk of relatively high energy prices occurring from time to time. However, managing this risk is not an insurmountable task and can be dealt with through standard hedging approaches.

If the strike price is set too low, for instance equal to the marginal cost of an efficient mid-merit generator, consumers may feel protected against price spikes, but the scheme will fail to encourage investment in mid-merit or peaking generators – one of its main purposes – since the low strike price exposes them to "volume risk" or "scheduling risk".

Scheduling risk is a particular form of volume risk facing capacity providers who have ROs (or CFDs) in place but whose generator plants that do not run all the time. It is the risk that the RO is called (and incurs difference payments) at times when the plant is not running (and so not earning any offsetting revenues). That situation arises when the MRP is (1) above the RO strike price but (2) below the marginal cost of generating electricity from these plants. The first condition arises often when the strike price is set at a low level. The second condition arises because some mid-merit and peaking generators have quite high marginal costs for running in short periods of system stress, given their start-up costs and ramping constraints. A low strike price therefore exposes some capacity providers to substantial (and unnecessary[2]) risk. We discuss of difficulties in hedging further in Section 2.2.1.

The consultation document recognises the need to set the strike price so that it reflects the short run costs of the highest cost ("marginal") generator in the market. In Ireland this is expected to be peaking gas or oil-fired plant.

However, to avoid "scheduling risk", the value used to set the strike price should include all the marginal costs of generating electricity, the not just the variable or "incremental" cost of generating at peak times, once the plant is running. For a peaking generator, the cost of reaching full output at times of system stress includes not just the incremental costs of generating, but also some additional costs, such as the cost of starting the plant. The additional cost may also include a running cost per hour and (if necessary) the cost of running the plant out-of-merit (i.e. at a loss) in the minutes before and after the period of system stress, when it is ramping up to and down from full output.

The SEM Consultation acknowledges but does not fully consider these inter-temporal issues.[3] However, it is not unusual for electricity markets to attribute the additional costs of generation to periods of peak demand, or system stress. For instance, the rules of the old Electricity Pool of England and Wales (1990-2001) incorporated these additional costs into the formula for the System Marginal Price. Other markets expect and allow generators to include these costs in their offer prices per MWh generated at such times. When defining a formula for the strike price, the formula will either have to incorporate the additional costs of peaking generation in the formula explicitly, rather than relying on generator's including them in offer prices. Alternatively, the strike price could be set with reference to VOLL, which would eliminate the issues associated with incorporating the full costs of the marginal plant altogether.

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2 ISO-NE is proposing to eliminate the Peak Energy Rent adjustment from its CRM, due to its poor performance as a hedge for Loads and the fact that hedging can be provided adequately by other means. This change would eliminate the problem for generators identified here.

3 See SEM Consultation Section 3.2.2 and footnote 20.

2.1.2. Single or multiple ("grandfathered") strike prices

The consultation document asks a question about the duration of the strike price – whether there should be a single strike price at any one time (updated as discussed below), or whether the reference unit for each strike price should be fixed ("grandfathered") at the time when the RO is issued, which would lead to multiple strike prices at the same time. (See paragraph 3.2.6 and question A)c. in paragraph 3.10.1.)

The consultation suggests that "grandfathering" the reference unit might be beneficial for investment in new capacity, but notes that the resulting multiplication of strike prices might make it difficult to manage the risk of a portfolio. In practice, the latter argument dominates the former. A vintaged strike price would tend to reduce liquidity in the CfDs and increase the cost of risk management. Market participants are less likely to invest if they are less able to manage their risks because the cost of risk management is high.

The purpose of ROs is to limit exposure to very high market prices, not to hedge specific generators. Investors in new capacity will not necessarily build plant with the same marginal costs or running regime as the reference unit. Thus, ROs will not provide investors in new capacity with their main tool for hedging market risk. Investors who want to share electricity market risks will still have to rely on the contracts they sign with buyers.

The parties to such contracts will have to adjust them so that they do not overlap with the ROs, which would otherwise undermine their function as a tool for risk management. (The adjustment will take the form of an exemption from difference payments when the MRP exceeds the RO strike price, or a call option that offsets the main contract in such conditions.) These adjustments should not, ideally, limit the tradeability of the associated contracts. If different vintages of RO have different strike prices, the resulting adjustments would be specific to certain generators. That would limit their value in trade and hamper contract market liquidity. Such contracts would not be attractive to new investors.

Overall, therefore, we conclude that investors in new capacity would not benefit from having some tailor-made RO with a vintaged strike price that would upset their role as a tool for risk management. Instead, investors are likely to favour ROs and contracts that follow a standard design with a common strike price at any one time.

2.1.3. Updating the strike price over time

The method by which the strike price is updated over time to reflect changing market conditions is another important determinant of the risks associated with the level of strike price and the overall efficiency of the mechanism.

If the strike price is tied to level of VOLL then updating the strike price is simply a matter of adjusting for inflation. However, if the strike price is tied to the costs of the marginal generator, the process of updating is inherently more unpredictable.

Above, we discussed how to avoid "scheduling risk" by basing the strike price on the marginal costs of the highest cost ("peaking") generator, including incremental cost of generating and the additional costs of reaching full output. The formula for defining the strike price at any time needs to preserve this condition, at the very least by reflecting changes in the price of fuel for the reference unit, and if necessary by switching to a more expensive reference unit when there is a change in available technologies or in relative generation costs.

The precise details of this updating will be relatively simple and are not important to investors, provided that the method of updating the strike price is (1) stable, (2) public and (3) clearly defined. Investors and market participants will then be able to manage their risks effectively by allowing for the effects of this method (or by referring directly to this method) in the adjustments to their contracts mentioned above.

2.2. Setting a Market Reference Price

The SEM Consultation provides a set of criteria for assessing various options for the Marginal Reference Price (MRP)[4]. For the purposes of this discussion, we have combined these criteria into more concise objectives. In summary, the choice of the market reference price aims to achieve three main objectives:

- to facilitate risk management for market participants;
- to provide incentives to provide capacity when there is a shortage; and
- to encourage competition and liquidity in the wholesale markets.

The remainder of this section discusses these three objectives in detail. We cover the RA’s first criteria on security of supply and incentives for capacity provision in the discussion of our second objective. We cover the RA’s second, fourth and fifth criteria on EU internal market integration, liquidity and market power, respectively, in the discussion of our third objective. And finally, we cover the RA’s third criteria, on efficiency and risk management in the discussion of our first objective.

2.2.1. The market reference price should facilitate risk management

A capacity mechanism introduces an additional set of financial flows between market participants. These flows are inherently uncertain and are therefore a potential source of additional risk for market participants, unless their variation offsets variation in other flows. The effect of the ROs must therefore be evaluated against the background of other financial flows, from markets and contracts.

When choosing a reference price the primary source of new risk is the basis risk caused by trading in a different market from the one used to settle the Reliability Options. The primary method of hedging the new risks created by ROs is likely to be a shift in trading into the market from which the MRP is taken. In principle, other approaches exist to manage these risks through alterations to CFD contracts, for example by including explicit adjustments for any differences in price between markets with the contracts. However in practice, such adjustments may not arise because:

- the quantity traded under the CFD is set in advance, whilst the quantities sold in the DAM and BM vary at short notice, so the CFD may not cover the actual quantity exposed to the

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4 See SEM Consultation, Section 3.5

price differential – unless the relative quantities are tied to a particular generator, making the CFD difficult to trade;

- the Balancing Market price may not even be identical to the balancing price received by an individual generator, if ever a pay-as-bid pricing rule applies (either in general or, e.g., for generators behind a transmission constraint).
- traders may find it difficult to agree upon a common contractual form that achieves this adjustment
- volumes of CFDs and ROs may not match in total, so that generators and suppliers cannot actually achieve a risk-hedging combination of CFDs and ROs.

This "modified CFD" approach avoids the complexity of "blending" market reference prices, but only by forcing market participants into an equivalent "blending" of contract volumes. Consequently, this approach of adjusting the CFD contracts to account for price differentials between the trading and reference price, pushes the complexity to the generator and supplier for managing risks rather than adopting administrative procedures that help participants.

We are not aware of any cases where traders have adjusted their CFDs in the manner described here to cope with the overlap between the hedging properties of CFDs and ROs. We also note that ISO NE referred to persistent difficulties over risk management in its proposals to reform the capacity mechanism in New England. Therefore, whilst we recognise that there may exist solutions to the risk-hedging problems caused by ROs (especially those with low strike prices), we do not believe that these solutions can necessarily be implemented in contracting timescales. A more likely outcome is either a decline in liquidity, as different traders adopt different contractual solutions, or the persistence of the problem with risk hedging that harms investment incentives.

2.2.2. The market reference price does not provide short term incentives for generation or consumption

The reference price and the extent which it reflects market conditions influences the incentives for providing capacity.[5] To obtain a clear picture of how the MRP influences the incentives for providing capacity we consider the incentives facing a bidder in two cases when market prices are high (above the RO strike price):

1) when generator output is less than the de-rated capacity of the plant, i.e. less than the generator's contracted quantity of ROs; and
2) when generator output is greater than the de-rated capacity of the plant, i.e. more than the generator's contracted quantity of ROs.

In the first case, when output is less than the RO contract quantity, capacity providers face a choice between two outcomes. They can provide the capacity, receive the market revenue and then make a difference payment to the TSO out of revenues received from market prices above the RO strike price. Alternatively, they can fail to provide the capacity and still make the same difference payment to the TSO. The difference between these two scenarios lies

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5 See SEM Consultation, Section 3.65

only in the revenues at market price and so the incentive to provide or withdraw any additional unit of capacity is the market price received for output from the marginal unit of capacity. Importantly, this market price need not be from same market that is used to set the MRP; generators are free to seek out the market with the highest price. It is only from a risk minimisation perspective that it is rational to offer capacity into the RO reference market.

In the second case, when the capacity provider is already providing sufficient capacity to meet the RO contract quantity then the capacity provider will simply receive its marginal revenue from the market in which the additional capacity is offered and accepted.

Hence, irrespective of the market where the MRP is set, the incentive to provide an additional unit of capacity comes from the achieved market price for the output of that unit. Therefore, incentives are only driven by market prices. The choice of MRP only affects operating decisions by influencing the requirements for risk management.

In a sense, therefore, the RAs can separate two decisions. They can set the formula for prices in the DAM and BM to reflect the expected (or current) degree of scarcity; this decision will determine the short run incentive to make capacity available. They can then select the reference market for the MRP in ROs as a contribution towards the long run incentive for building and maintaining capacity. As discussed below, the latter decision might take into account the need to focus trade in certain markets (as the by-product of efficient risk management) both to facilitate cross-border trade and to promote competition and liquidity within the I-SEM.

2.2.3. A market reference price should promote competition and liquidity

The choice of market reference price should be taken in the knowledge that it will determine the manner in which generators and suppliers wish to participate in each of the wholesale electricity markets. Active participation and liquidity in both the day-ahead and balancing markets is important for risk management and also, in a market with a single dominant firm, namely ESB, for restricting the potential exercise of market power. The remainder of this chapter therefore appraises three of the four options for the choice of MRP, set out in the SEM Consultation,[6] in terms of their consequences for liquidity and market power. These options are:

1. Balancing Market price;
2. Intra-Day Market price (which we do not consider in detail);
3. Day-ahead Market price; and
4. Mixed reference price schemes (as found, e.g., in Italy).

In the following section we discuss options for setting the reference price and how these perform against the criteria set out above. Note that we do not consider at length the possibility of using the Intra-day Market, due to the low liquidity and the difficulty of choosing a single reference price in a market with continuous trading.

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6 See SEM Consultation, Section 3.6

2.3. Option 1: Balancing Market for Reference Price

Option 1 in the SEM Consultation involves setting the MRP as 100% of the Balancing Market price – assuming that the Balancing Market is structured so that it produces an unequivocal price for each trading period. In our discussion of this Option, we consider the issue of administrative scarcity pricing, which is raised within the SEM Consultation[7].

2.3.1. Risk management and sharing

The use of the BM price as the MRP would create a new risk for market participants to manage. In many descriptions of the future system, it is assumed (for reasons that are not always clearly stated) that most output is sold in the DAM and that most contracts refer to the DAM or the DAM price in their settlement. In this case, referring to the BM price in ROs would create either a new basis risk, or an incentive to shift the trade in physical output and contracts from the DAM to the BM.

The BM price reflects actual conditions as they arise, whereas the DAM price reflects expected conditions and may not capture the effect of unexpected changes in demand, network conditions or generator availability. If contracts continued to be settled against the DAM price, whilst ROs were settled against the BM price, market participants would face basis risk due to the difference between the prices, and might find it difficult to adjust their contracts to avoid the overlap of hedging (see Appendix D). Any additional risk placed on capacity providers would be expected to increase their costs and hence prices to consumers. However, within the SEM and I-SEM, the ability to include these costs in offer prices may be constrained by regulation, so that capacity providers would have to include the costs of basis risk instead in their bids for ROs.

A more likely outcome is for market participants to change the way they trade, in order to eliminate the basis risk in the first place. If the BM allows them to sell their output at the MRP (i.e. if it sets a single price for every trading period), generators can avoid basis risk by selling their output in the BM and signing CFDs settled against the BM price up to the RO strike price This trading strategy might require a reform of system operation, since the TSO would no longer be able to count on the forecast of output and offer prices provided by the DAM. Forcing generators to make day-ahead offers would preserve the current status of the DAM, but would also impose basis risk on them.

2.3.2. Incentives for capacity provision

The BM is likely to be the most volatile and unpredictable of all electricity market prices, since it reflects all the unpredictable changes in system conditions. Generators, suppliers and customers would be insulated from the financial effects of that volatility by the hedging properties of CFDs and ROs, especially if they were settled against the BM price. The short term incentive to provide capacity depends on the value of the BM in both normal conditions and periods of system stress, even if generators possess CFDs and ROs, since any deviation in output above or below the volume of these contracts will attract the BM price. In the

7 See SEM Consultation, Section 3.4

medium-to-long term, the incentive to invest in building capacity and keeping it available depends on the revenue to be obtained from CFDs and ROs, which depends in turn on the expected future value of the BM price. The formula for the BM price therefore underpins all incentives for capacity provision.

The strength of this incentive depends on a number of factors, including:

- regulatory constraints on offers and bids submitted into the Balancing Market;
- whether administrative scarcity pricing is applied in the BM and, if it is:
  - how the administered value is set;
  - the conditions in which it is applied; and
  - the frequency with which those conditions are expected to arise (or their probability).

The answers to these questions will affect every one of the Options for the MRP. In general, the lower the BM price is expected to be in times of system stress (if the administered scarcity price is low or absent, or if scarcity is unlikely to occur), the lower the value that market participants will attribute to ROs and the more incentives will rely on additional penalties for not providing physical capacity. The ETA work stream will need to take into consideration the interaction between the BM price and the incentive to provide capacity and the hedging instruments required by suppliers.

2.3.3. Competition and liquidity

The RAs noted in the SEM Consultation[8] that setting Balancing Market price as the MRP may reduce liquidity in the Day-Ahead Market. Under the EU target model, market coupling is currently performed on a day-ahead basis, so reduced liquidity may interfere with an efficient market coupling process.

One proposed solution is to make it mandatory for bidders to offer the output from their capacity into the DAM (see Sections 3.5.1 and 3.6.5 of the SEM Consultation). However, making bidding compulsory in the DAM raises risks for capacity providers that have uncertainty around their future output at the day-ahead stage, e.g. intermittent generation, as they cannot adequately respond to changes in the technical characteristics of their own plant by bidding in the balancing market.

One way to support compulsory bidding in the DAM by maintaining flexibility for participants is the scheme known as “virtual bidding”. Virtual bidding allows market participants to take financial positions in the physical electricity markets,[9] i.e. to submit offers and bids unrelated to actual generation or consumption. It helps to promote price convergence between the two markets by allowing bidders to manage their positions in each market more freely and to arbitrage prices between markets. In this case, it would also help them manage basis risk, if ROs (and CFDs) were settled against the BM price. Generators would be obliged to *offer* their plant into the DAM, but would then be allowed to place a

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[8] See SEM Consultation, Section 3.6.5

[9] Celebi, M., Hajos, A., & Hanser, P. Q. (2010). Virtual bidding: the good, the bad and the ugly. The Electricity Journal, 23(5), 16-25.

virtual *bid* in the DAM to buy the same amounts at the same prices, so that in net terms they would close out their position in the DAM. That would then free them up to participate in the BM.

This scheme preserves the benefits of a liquid DAM whilst avoiding the need to impose basis risk on market participants who sign up for ROs settled against the BM price.

However, the implementation of virtual bidding may provide opportunities for capacity providers to manipulate their bids to alter the market reference price. This may be particularly important in the context of the Irish market given ESB’s market position. The market power mitigation work stream should take account of the potential market power issues associated with virtual bidding.

2.4. Option 2: Intra-Day Market for Reference Price

Option 2 in the SEM Consultation would take the MRP from the Intra-Day Market (IDM). We do not consider this option in detail, as it seems to us to be impractical. The IDM consists either of a number of separate markets operating at defined intervals during the day, or as a continuous market in which trades can take place at any time. Neither of these possibilities would be capable of setting a useful reference price for settling CFDs or ROs.

2.5. Option 3: Day-Ahead Market for Reference Price

Option 3 in the SEM Consultation involves setting the market reference price as 100% of the day-ahead market price.

2.5.1. Risk management and sharing

If the MRP is set as the DAM price then both operation of the system by the TSO and risk management is likely to follow the general pattern that seemed to be envisaged in the I-SEM HLD.

To manage their risks efficiently, generators will want to sell their output in the DAM, and to sign CFDs referenced against the DAM price up to the RO strike price, at least to the same extent that they possess ROs. Only minor deviations would be bought or sold in the Intra-Day or Balancing Markets.

The incentive to participate in the DAM will also complement – and might even replace – any obligation on generators to offer their plant to the DAM. The TSO would therefore continue to receive day-ahead notice of availabilities and offer prices, for use in scheduling and despatching generator capacity.

This Option therefore promises a minimum (albeit some) amount of disruption to arrangements for trading and despatch that generally seem to be envisaged in the I-SEM HLD.

2.5.2. Incentives for capacity provision

The SEM consultation argues that the use of the DAM price as the MRP provides weak incentives to provide capacity, because the DAM price is less closely aligned with actual system conditions than the BM price[10]. At the time when the DAM clears, the price only reflects a best guess of what system conditions will be like at the time of actual dispatch. To the extent that system stress arises only when system conditions change between the clearing of the DAM and BM, the DAM price provides a muted or inaccurate incentive for the efficient provision of capacity.

However, as discussed above in Section 2.2.2, settlement of ROs does not in itself provide the incentive for efficient provision of capacity. ROs – or other forms of capacity mechanisms - give investors a more stable and predictable source of revenue for financing investment in capacity than relying on occasional spikes in the DAM or BM price at times of system stress. The purpose of the ROs is therefore to encourage investors to build more capacity and to invest more in keeping it available. Actual decisions to make capacity available at times of system stress, and to generate output from it, depend on the actual prices that arise in the DAM, IDM and, in particular, the BM. That is because the DAM price will determine a generator's reward for additional sales (or the cost of purchase) in the DAM relative to the volume of its ROs and CFDs, whilst the BM price defines the equivalent reward/cost for additional sales or purchases in the BM relative to the volume of sales in the DAM.

Thus, the incentive to respond efficiently to signals in the BM persists, even if ROs are settled against the DAM.

2.5.3. Competition and liquidity

Setting the DAM price as the MRP is likely to encourage generators and suppliers to trade through this market to minimise their risk. Under a RO scheme with the DAM as the MRP, exposure to the basis risk is minimised by trading equivalent volumes in DAM.

Setting the DAM as the MRP is therefore likely to increase participation and liquidity in the DAM. That outcome would contribute towards the efficiency of day-ahead market coupling within the EU target model.

This increased participation in the DAM may reduce participation and liquidity in the Balancing Market, unless, as we understand will be the case in I-SEM, the market rules also ensure participants make capacity available in the balancing market. At times of system stress, lack of liquidity in the BM could create circumstances where dominant firms emerge and can exercise market power to raise or lower BM prices (whichever suits their contract position). The extent to which such outcomes can be prevented by regulatory oversight is not yet clear.

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[10] See SEM Consultation, Section 3.6.2

2.6. Option 4: Mixed Schemes

A mixed scheme involves setting a reference price based on some combination of market prices. This section considers the two approaches outlined in the SEM Consultation, namely:

- a blended scheme (Option 4a); and
- a split scheme (Option 4b)

Under both these approaches, the Market Reference Price for ROs is set by taking a weighted average of the prices in the DAM and BM. The SEM Consultation does not state explicitly how these schemes would reconcile sales of capacity in each market with the volume of ROs. However, the two most likely schemes seem to correspond to the “blended” and “split” schemes, as we show below for the case where.

- capacity providers have ROs for 8,000 MW and;
- they sell 7,000 MW in the DAM and 2,000 MW in the BM.

The price could be an average of DAM and BM prices weighted in the proportion 7,000:2,000, or the formula could take only the volume of BM trades needed to match the RO volume, i.e. use weighting of 7,000:1,000.

The term “blending” seems to apply best to the weights derived from actual sales (7,000:2,000). Below, we examine the incentive properties of such a rule, i.e. setting the proportions based on total sales in each market – in this case, weighting the DAM and BM prices respectively by 7/9 and 2/9.

Under a split approach, ROs are cleared against the DAM price for the volume offered into and accepted in the DAM. A volume of ROs equal to the capacity accepted in the BM, up to the remaining RO contract volume, is cleared against the BM price. In the above example this would equate to 7,000 MW being cleared against the DAM price and 1,000 MW being cleared against the BM price, or a weighting of 7,000:1,000. That approach would allow market participants to hedge by matching their CFD volumes to their sales volumes and offsetting the RO volume (see **Box 1** in Appendix D). The other 1,000 MW of sales in the BM would be unhedged and would act as an accurate, short term incentive for providing capacity. (The split scheme could also make the adjustment to DAM volumes, i.e. use weighting of 6,000:2,000, but the rationale for using such a method seems weak.)

A split scheme of this type is currently proposed for the Italian capacity market which is intended to come into operation through auctions for capacity contracts in late 2015. See Appendix A for a case study on the Italian scheme.

2.6.1. Risk management and sharing

Mixed schemes are intended to help capacity providers to manage the risks associated with offering capacity into multiple markets, by setting the applicable MRP based on actual bidding behaviour. For the sector as a whole, the basis risk associated with being dispatched at a market price that is different from the MRP is reduced by giving that sale a weight in the formula for the MRP. However, in practice, the scheme would seem to work only for the sector as a whole, and to leave individual generators exposed to basis risk of a particularly complex and unpredictable type.

For instance, in the example above, any small generator that sells 70 MW in the DAM and 20 MW in the BM would receive the hedging benefits (if any) of both the blended and split schemes. However, if the same generator sold 80 MW in the DAM and 10 MW in the BM, it would face basis risk on the 10 MW by which its own sales were misaligned with the sales of the sector as a whole.

Most generators would in practice sell different proportions of their output in the DAM and BM. Defining a different MRP for each capacity provider, using their own proportions of sales in each market, would create another problem for hedging, since each holder of ROs would want a different kind of adjustment to their CFDs to avoid the hedging. The result would be a disparate and illiquid market for CFDs.

Thus, neither the blended scheme nor the split scheme seem to offer the purported benefits for risk management – unless, for some reason, market participants proved unable to hedge the risks inherent in Options 1 and 3 using the methods set out above.

2.6.2. Incentives for capacity provision

In the previous Options, the marginal incentive to provide additional capacity at short notice remains the BM price, if the volume of ROs (and CFDs) is fixed. Adjusting the MRP for ROs in the light of actual sales to each market would affect that incentive, at least to some extent for large companies.

When deciding how much capacity to sell in the BM, a generator knows that it will be rewarded at the BM price. The ability to manipulate this price would distort incentives, as in any market, but mixed schemes create an additional dimension for market manipulation. Large generators will also know that a decision to provide additional capacity to the BM will affect the weighted MRP used for settlement of its ROs. That effect might conceivably either dampen or exaggerate the incentive to provide capacity.

For example, if the BM price is greater than the DAM, every additional unit of capacity accepted in the BM raises the Market Reference Price and the payment per MW to the TSO, due to the increase in the weighted average price. In this case, the weighting approach in the scheme dampens the incentive to provide capacity, as the capacity provider will not receive the full BM price. See Appendix C for a formal derivation of this result.

2.6.3. Competition and liquidity

The primary driver behind the adoption of a scheme that incorporates both the DAM and BM prices is the intention of minimising distortions to the level of participation in the two markets (DAM and BM). These mixed approaches would be attractive from the perspective of integration with EU market coupling, if they facilitate or encourage continued participation in the DAM.

However, the complexity inherent in these schemes may have the unintended consequence of discouraging participation in particular markets, as capacity providers look for ways to improve their risk management and approach to bidding. For example, the complexity associated with managing risks in CFDs under a complex MRP rule may encourage capacity providers to concentrate on participating only in the BM, to reduce the complexity of their contract and risk management strategy.

In addition, schemes with a high degree of complexity may favour larger firms relative to smaller firms, as larger firms will typically be better equipped to deal with complexity and to exploit potential opportunities.

2.7. Conclusions

The RAs have chosen Reliability Options (ROs) as the high-level design for the capacity mechanism in the I-SEM. Holders of ROs will have to pay the difference between the market reference price and the strike price to the system operator whenever the market reference price rises above the strike price. In the next stage of design work on the capacity market, the RAs will select the strike price and reference prices for the RO contracts.

- **The level of the strike price**

The risks surrounding the selection of the RO strike price are asymmetric. In principle, a range of different strike prices would offer some additional incentive to provide capacity. However, practical considerations point towards setting a strike price towards the higher end of the feasible range. The lower the strike price, the more often holders of ROs will pay money to the system operator, the more valuable ROs will be, and the greater the proportion of market participants' revenues will pass through the capacity market, rather than the energy market. Many aspects of the method used to recycle revenues from holders of capacity to supply businesses create unhedgeable risks for participants, and ultimately costs for consumers, with no offsetting benefit in additional security of supply. All other things being equal, the lower the strike price, the larger the volume of capacity holders' remuneration flowing through the capacity market, and the larger the unnecessary risks and costs that will ultimately be borne by consumers. ISO-NE is proposing to eliminate the Peak Energy Rent adjustment from its CRM, due to its poor performance as a hedge for Loads and the fact that hedging can be provided adequately by other means. This change would eliminate the problem for generators identified here.

- **Choice of Market Reference Price**

The Market Reference Price (MRP) used to settle ROs must be taken from a "reference market". The choice of this reference market does not materially affect the incentives for delivery of energy (or capacity) during scarcity events: irrespective of the Market Reference Price chosen, and regardless how many ROs or Contracts for Difference (CFDs) each market participant holds, the incentive (i.e. the additional revenue) for providing additional output in real time is the Balancing Market price. However, the selection of Market Reference Price will drive trading and contracting behaviour. Traders will seek to minimise their exposure to basis risk and therefore have an incentive to trade physical output at the MRP and to sign CFDs settled against the MRP, which has important implications for competition and liquidity.

Market participants will shift trade into the relevant reference market as a way to eliminate basis risk. If I-SEM rules direct market participants to trade in markets other than the reference market, they will need to find (and be allowed to adopt) methods to mitigate that risk. For instance, the use of "virtual bids" would allow market participants to pass electricity right through the directed market and into the reference market; however, this solution may give rise to other potential problems, such as creating opportunities for manipulating market prices.

Taking the MRP from the Balancing Market would align all prices and risks, but would cause trade to focus on the BM and to shift away from the Day-Ahead Market. That might harm the liquidity of cross-border market coupling. Forcing market participants to trade in the DAM would create basis risk unless *either* the MRP was taken from the DAM *or* the MRP was taken from the BM and market participants could use virtual bids to transfer electricity from the DAM to the BM. The Intra-Day Market will not be liquid enough to provide a relevant MRP. Mixed schemes for defining the MRP bring additional complexity into the settlement of ROs and CFDs. As such, they increase the difficulty of hedging whilst offering little if any reduction in the exposure to basis risk.

The design of the CRM would benefit from industry input on the implications of particular strike prices and MRPs for risk and liquidity, organised as a workstream on pricing.

3. Capacity Requirements and Obligations

This chapter reviews possible methods for setting the capacity requirement and the corresponding obligations on individual plants, in terms of (1) the quantity of capacity provided and (2) load following obligations.

In discussing these rules, we have adopted the position that, in order to be "stable", rules must be "adaptive". By this, we mean that the rules must be flexible enough to accommodate changing circumstances and should not require further regulatory intervention (and use of discretion) to adapt to developments in the market, such as the adoption of new technologies. In practice, this means avoiding rules that are specific to individual technologies ("wind", "solar") or which apply subjective concepts and measurements ("intermittency") but should instead refer to observable operating parameters (such as whether or not they are "despatchable", i.e. subject to central despatch).

To maximise "transparency", and hence "economic efficiency", we assume that the capacity requirement must be defined by a mechanistic formula that uses publicly available data on objectively defined variables. Such an approach allows market participants to make informed decisions about how the capacity requirement will be set in the future and allows market participants to produce their own assessments of demand in future auctions for capacity rights.

Our discussion of capacity obligations therefore focuses largely on how to foster economic efficiency by creating a transparent, but adaptive, measure of capacity requirements and obligations.

We note in passing that the SEM Consultation contains no discussion of the process for trading or transferring obligations between capacity providers. This appears to be a major omission which will need to be addressed in the near future. Given conditions in the market for ROs, with one central buyer, we do not envisage a liquid market in ROs emerging any time soon. However, capacity providers will undoubtedly want to be able to transfer ROs to others, if the availability of their plants changes unexpectedly. For the sake of transparency and efficiency, the process for registering such transfers of obligations needs to be defined from the outset.

3.1. Defining Capacity and Setting the Capacity Requirement

A stable, transparent and adaptive methodology must be able to deal with different technical capabilities, both now and in the future. Given the uncertainty surrounding the future characteristics and prevalence of individual technologies, it is difficult to base a stable scheme on technology-specific rules. Instead, to give market participants a long term view of the capacity market, it needs to develop a conceptual approach to assessing the capacity contribution of each potential source.

For example, consider the capacity contribution of wind capacity. In many markets, it is set as a rather low percentage of nameplate capacity, because the expected output of wind farms is rather low during periods of system stress, not least because such periods may be *caused* by a drop in output from wind farms. Given their special situation, some schemes adopt specific rules for wind farms, such as excluding them from capacity schemes altogether.

However, in the future, if the cost of electricity storage falls, developers might start to combine wind farms with storage facilities and then to claim that they are able to provide guaranteed capacity at times of system stress. Rules defined for wind technologies would then be outdated and inadequate. A new rule for the technology of "wind+storage" would be required. This rule would have to measure capacity contribution of such plant, taking into account the fixed capacity of the storage in MW, but also its limited volume in MWh, the possibility that the storage might not be completely full when the system came under stress, and the degree of control over its output granted to the TSO (its "despatchability").

"Adaptive" rules would accommodate these factors by focusing on the likely ability of the plant to provide energy at times of system stress, based where possible on actual experience, rather than on the supposed characteristics of a particular technology.

We note the question raised in paragraph 2.1.2 of the SEM Consultation as to whether the security standard should be changed. We cannot see why the introduction of a new scheme would require a change to the security standard, which depends on other factors. In economic terms, the security standard should seek on average to achieve a cost of outages (Value of Lost Load times Hours of Lost Load per annum) that is equal to the annualised cost of peaking capacity. Only changes in these parameters would merit a change in the security standard. The design of a CRM should merely reflect the current security standard (and render any other incentives for capacity redundant).

3.2. De-Rating Factors

The contribution of capacity towards total security of supply will vary between different technologies and, within a technology, between different plants or sources. Typically, the de-rating factor applied to nameplate capacity is a factor based on the forced outage rate ascribed to the plant, e.g.:

*Capacity Provided = Nameplate Capacity * (1 – Forced Outage Rate).*

To maintain an efficient balance of supply and demand, this formula needs to measure each source's expected contribution to supply at times of system stress. It also needs to maintain the incentive to make capacity available efficiently. This section outlines the key decisions around the definition of forced outage rates and de-rating factors.

3.2.1. Plant-specific versus technology-specific factors

De-rating factors can be defined for individual plants or as averages for all the plants using a distinct technology.

The discussion above highlighted the difficulty with referring to individual technologies in the rules on measuring capacity. A plant-specific approach is also likely to create stronger incentives for efficient management of capacity.

If individual plants are rewarded for their capacity using an average technology-specific factor, they will have little incentive to invest in raising their own capacity above this level (or in preventing it from falling below it). Only in certain special circumstances would it be necessary to adopt a more broadly defined measure:

- When a plant first comes into operation and has no established history from which its performance can be measured; and

- Generators with strong interdependence of availability, such as a common fuel source with limited deliverability, might potentially be accorded an aggregate measure of capacity, as a more accurate reflection of their actual contribution to potential supplies at times of system stress.

3.2.2. Historical versus forecast performance

A historical approach to setting the de-rating factor uses that actual observed performance of the plant to set its de-rating factor. A forecast approach involves assessing the technical characteristics of the capacity provider and using benchmarks of performance from similar plants to produce a forecast of its likely performance.

A historical approach fits the need for use of objective and publicly available data. However, the time period of the data used to set a historical rate needs to be sufficiently long to eliminate the potential for gaming the process. If the time period is too short, a generator may be able to game the process by focussing its effort on generating during the period when historical performance is assessed, rather than the period when its output or capacity is most valuable to consumers. Using data from a longer time period and providing incentives to exceed historical performance (and/or the current volume of ROs) can help to neutralise the temptation to game the process in this way.

A forecast approach might conceivably be more accurate, if capacity contributions have to be defined for auctions so far in the future that recent experience is a poor guide to likely performance. However, using forecast data can mean using subjective data, undermining the transparency of the scheme and the efficiency of decisions based upon it. It would only be advisable to use such forecasts when there are strong reasons to believe the future performance will differ significantly from historical performance, and there is a sound basis for measuring the trend in performance in objective and publicly available data. In any other cases, the benefit of using forecast data for accuracy is unlikely to outweigh the cost to transparency.

3.2.3. Non-firm access and de-rating

The treatment of plants without firm access raised questions around the allocation of risk within the system and the interaction of the capacity market incentives with transmission infrastructure. In order to reflect their capacity contribution accurately, de-rating factors applied to generators should capture their likely contribution to supply at times of system stress and hence should be adjusted to reflect the likelihood of the generator not gaining network access at such times. Generators with non-firm access need to be subject to penalties for failure to provide the de-rated capacity, subject to the provisions for exemption for failures caused by external factors (e.g. decisions by the TSO to withdraw network capacity from generators who have paid for a deep connection).

We note in passing that, at many times of system stress, output from wind farms and/or solar plants will be depressed. In such cases, there may well be enough network capacity to accommodate generators who lack firm access. The impact of non-firm access should therefore be assessed by taking account of the degree of coincidence between times of system stress and denial of access.

3.2.4. DSR and baseline

Any special treatment of Demand-Side Response (DSR) raises a concern over double remuneration of the supposed response – once through the saving in energy charges due to the reduction in consumption, and once through the payment for units of DSR actually provided. There is no comparable problem with double-counting of generation, because all energy production is accounted for in a market, whereas the payment for units of DSR may not be. The efficient solution lies in adopting a similar approach to settling the "baseline" for DSR, as we explain below.

Most DSR schemes ask the consumer (or its representative) to declare both their actual (i.e. metered) consumption and how much they have reduced it below their desired level of consumption (i.e. their DSR). The latter item is unobservable and highly subjective – even the level of consumption just before DSR is invoked may be a misleading measure of what the consumer would have consumed at time of system stress and very high prices.

A better approach (comparable with that adopted for generators) is to ask the consumer to commit to the desired level of consumption by signing a contract and showing that it has committed to pay for a certain volume of electricity in the period concerned. The consumer (and no other market participant) can offer to sell some or all of this volume back into the Balancing Market, as DSR. This approach effectively puts an efficient market price on the "declaration" of the desired level of consumption. It is rare for DSR schemes to apply this economically efficient approach to measuring the baseline.

Any alternative scheme needs to be designed to avoid or to minimise the cost of double counting DSR. Achieving this outcome requires (1) that the baseline methodology is robust as objective as possible (i.e. difficult to game) and (2) that the baseline level of demand *before* DSR, rather than the actual level of demand *after* any reduction, enters into the formula used to define the total capacity requirement.

3.3. Load Following Obligations

For the sake of efficiency, the rules for defining the load following obligation of each source of capacity must allow their providers to manage their risks. One risk facing capacity providers is the risk that they are not (or cannot be) despatched to run during a short period of system stress and high market prices, because their plant would take too long to start up, or is temporarily unavailable. A load following obligation helps to mitigate the risk to a capacity provider of not being dispatched during a period of capacity scarcity by reducing the obligation on the holder of any ROs to provide capacity in proportion to the level of demand and hence the relative scarcity of supply.

The SEM consultation outlines a proposed methodology[11] for setting the load following obligation based on the following formula:

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[11] See SEM Consultation, Section 3.7.

$$\frac{\textit{(Actual demand} + \textit{Operating Reserve Requirements} - \textit{Capacity provided by plant without an RO commitment)}}{\textit{Volume of RO sold}}$$

The formula is an attempt to adjust the obligation under the RO in line with the relative scarcity of capacity within the market at each point in time.

As the RAs acknowledge a major flaw with the proposed approach is in the treatment of plant without an RO commitment ("ineligible capacity")[12].The proposed approach leaves suppliers unhedged by the amount of ineligible capacity supplied into the market. This is particularly problematic with exemptions applied to intermittent generation as suppliers are unhedged and the extent to which they are unhedged is unpredictable due to the intermittent nature of the ineligible capacity.

The ISO NE takes a different approach to the load obligation which addresses the issue of ineligible plants. The ISO NE's proposed pay-for-performance scheme included all forms of capacity and therefore eliminates the issue of suppliers being unhedged.

The ISO NE defines its load following obligation by the following formulae, in which "Actual MW" means actual capacity provided, CSO stands for Capacity Supply Obligations and definitions of the other inputs are standard:

$$Performance\ Payment\ = Performance\ Payment\ Rate\ x\ Performance\ Score$$

$$Performance\ Score = Actual\ MW - CSO\ x\ Balancing\ Ratio\ (in\ \%)$$

$$Balancing\ Ratio\ (in\ \%) = \frac{\sum(Load + Reserve\ Requirement)}{\sum Capacity\ Obligations}$$

The Performance Payment Rate is the reward/penalty for variations in capacity set by ISO NE and is expected to be set at $2,000/MWh until 2021 after which it will increase. See Appendix B for more detail on the ISO NE load following obligation and pay-for-performance scheme.

As inspection of these formulae indicates, ISO NE takes a different approach to eligibility, including it in the definitions of both capacity requirement (the numerator of the Balancing Ratio) and the capacity obligations (the denominator). This formula can still have individual generators exposed to some risk, if their plant is temporarily unable to run, but at least their obligation is scaled down and the risk mitigated somewhat.

The scheme is similar to that proposed by the RAs in the SEM Consultation in that the quantity of the obligation is scaled according to the ratio of total capacity requirement (i.e. load/demand plus reserve margin) to the total volume of capacity obligations.[13] In the

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[12] See SEM Consultation, Sections 3.7.4 – 3.7.11

[13] In the case of the pay-for-performance scheme the difference between the actual output of the capacity provider and this scaled capacity obligation is then multiplied by the Performance Payment Rate to determine the penalty/reward to be

circumstance where plant is unable to generate because it has been instructed by the TSO not to do so, this would have to take it into account in adjusting the capacity obligation.

In summary, while a load following obligation mitigates the risk associated with high price events occurring at times of system stress when demand is below peak levels and some plant is unable to run, the extent to which this aim is achieved depends on the broader scheme design. The load-following rules reduce the capacity obligation in order to mitigate the risk that generators are unable to generate at an unforeseen time of system stress when total demand is low. In practice, adjusting the capacity obligation pro rata does not provide a perfect hedging adjustment, since actual output depends on a merit order. This change in the circumstances facing generators imposes on them an additional exogenous risk, that needs to be accommodated in the system of capacity penalties. The omission of intermittent generation from the formula would leave some consumption unhedged, and problem that is resolved (at least in part) by including all generation in the calculation.

3.4. Conclusions

The principles of adaptability and stability promote economic efficiency by reducing uncertainty for market participants. Market participants are able to make more efficient decisions when they can predict future the market outcomes and the future of the market mechanism itself. The CRM will achieve more efficient outcomes if the RAs develop formulae or conceptual frameworks to reduce scope for regulatory discretion and provide greater certainty to market participants. For example, to maximise transparency and efficiency, the RAs should specify formulae that define how the capacity requirement is calculated and how de-rating factors for new and existing plants will be measured; as far as possible, these formulae should use observable public data (i.e. historical data, not someone's forecasts). For the sake of adaptability and stability, such rules should as far as possible be unrelated to specific technologies (which may change in future), but should refer instead to general operating characteristics (such as "non-despatchability") and plant-specific data.

The design of the CRM would benefit from industry input on the technical and plant-level data to be used in CRM formulae, organised as a workstream on capacity definitions.

applied. Under the RAs proposed scheme, the scaled capacity obligation is used to calculate the capacity which falls under the RO contract and therefore the payment that the capacity provider must make to the TSO.

4. Penalties, Rewards and Enforcement

This chapter sets out the need for penalties to enforce capacity obligations, and the role they play in ensuring the effectiveness of the capacity mechanism.

In principle, any capacity mechanism should be designed to observe the following economic constraints:

- **Incentive Compatibility constraint:** If the instantaneous penalties during individual events are too low, generators will sign Reliability Options (for a low price) but will not provide physical capacity when it is needed.
- **Participation constraint:** If the penalties can accumulate over extended or multiple events to a large amount (relative to generator margins), the capacity market will have to settle at high prices to cover the risk of high penalties. Investors may even be unable to participate in the market, and hence be deterred from making capacity available, by the risk of bankruptcy due to high penalties.

The choice of mechanism is often a trade-off between these constraints. For instance, large instantaneous penalties provide strong incentives to make capacity available at times of system stress. However, the most efficient scheme design may cap (or mitigate) total penalties over some period(s) to encourage higher participation. In the most efficient scheme design, neither constraint dominates the other, and the trade-off finally adopted may involve detailed rules.

We note in passing that it may be difficult to apply this constraint to ESB, which may not be motivated by the same attitude to risks and rewards as a privately owned company. However, we know of no easy solution to this problem. The constraints apply in any case to the privately owned companies that are present in the market, or which may enter in the future.

The remainder of this section addresses the specific design questions around setting and enforcing penalties, the rationale for exemptions and the treatment of intermittent generation.

4.1. Setting Penalties and Rewards

Penalties and rewards provide additional incentives for capacity provision at times of system stress by decreasing or increasing the revenues of the capacity provider in cases where they under/over-perform relative to their capacity obligation.

To provide an incentive at the margin, incremental penalties and rewards must adjust revenues by more than the incremental cost of making additional capacity available. If the penalties are too low in any instant, a generator may be willing to accept the penalties and not provide capacity, thus rendering the scheme ineffective.

The appropriate level for *total* penalties and rewards depends on the characteristics of capacity providers, e.g. their flexibility and reliability. If a generator cannot respond to incentives, no matter how strong they are, no purpose is served by imposing penalties beyond a certain level (particularly the level that would bankrupt the generator). Accordingly, it may be optimal to offer capacity providers who differ in their ability to respond to incentives different regimes of reward and risk, as long as those differences can be objectively justified by technological criteria and can adapt to changing circumstances in the generation sector (such as new or hybrid technologies emerging). This application of differing regimes of risk and reward arises in any circumstance where there is uncertainty around the level of effort being put into delivering some output. Indeed, in such cases the efficient outcome involves a degree of risk-sharing between the parties to the contract, a finding that is well-established in the economy literature.[14]

Financial penalties should also be supplemented with other enforcement mechanisms to maximise the effectiveness of the mechanism. The primary tool in this respect is basing future participation in the scheme on past participation. For example, the de-rating factors of capacity providers that do not perform during stress events can be reduced down to reflect their poor performance. In the extreme case, capacity providers could also be excluded from the mechanism by restricting participation in the auctions for capacity obligations. This is particular important if the capacity mechanism has caps on the penalties incurred that restricts the possibility of negative payments as a result of participating in the scheme.

4.2. Exemptions and Caps

Allowing exemptions from penalties has a large effect on the allocation of risk within the capacity mechanism. Extensive exemptions mute the incentives provided by the capacity mechanism while allowing insufficient exemptions would place substantial risks on some capacity providers.

A number of factors outside the control of a capacity provider influence its ability to make capacity available. Imposing penalties when such events occur serves no purpose in terms of incentives and creates additional risk that threatens the desire to participate in the market. In general there are two approaches to handling these events:

1. exempt capacity providers from penalties arising from events outside of their control; and/or
2. limit the total penalty that any capacity provide can incur over a certain period.

The first approach preserves incentives in all other situations, but will inevitably require the RAs to exercise a degree of discretion in adjudicating when such events have arisen. The second approach involves less discretion, and a number of schemes already provide examples of multi-dimensional limits (monthly, yearly and so on), but limits can dampen or eliminate incentives when they are breached.

In ISO-NE, the current scheme is akin to the first approach, whereby exemptions are given to capacity providers if their inability to provide capacity was a result of a factor outside their control. This scheme has come under criticism for not providing sufficient incentives to capacity providers and is largely blamed for the current reliability issues in the market.

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14 Cheung, Steven N S (1969). "Transaction Costs, Risk Aversion, and the Choice of Contractual Arrangements". Journal of Law & Economics. 12 (1): 23–42

The ISO NE's proposal to move to the pay-for-performance scheme will be a step away from risk mitigation, because capacity providers must bear some of these risks.[15] In addition, the pay-for-performance scheme removes the penalties that arise from interaction with the energy market, by cancelling the rebates known as "Peak Energy Rents". However, the scheme would still set a limit on the penalties that capacity providers can incur over various periods, as per the second approach.[16] The aim of setting multiple limits over multiple time periods is to ensure that penalties cannot be excessive either in the short run or over a whole year, but also if possible, that the limit imposed on excessive penalties incurred in one short period does not invalidate the incentive effect of penalties incurred in the *next* period. This is particularly important for unplanned short term outages for which it is not possible to perform a secondary market trade to adjust the RO contract position.

The approach to exemptions and caps on penalties in the I-SEM capacity mechanism takes on added significance due to the recent introduction of a provision allowing TSOs to re-declare the achieved capacity of a generator at the level of their effective availability during network outages. This proposal exposes generators who participate in the RO to the risk of network operations, over which they have no control. We see three possible methods for managing this proposal within the RO scheme:

1. pass through of the implications to *suppliers and consumers*, i.e. give explicit exemptions from penalty on those occasions where the TSO re-declares plant availability due to a network outage;
2. pass the penalty over *to the TSO*, i.e., make the TSO liable for the penalty payments incurred by the plant due to its network outages; or
3. leave the risk with *capacity providers* and require them to manage the risk as best they can.

In circumstances where capacity providers have no control over the network outage, placing the risk on capacity providers does not provide any sharper incentives but threatens them with potential financial problems and even bankruptcy. The most efficient outcome is likely to be a combination of all three possible methods, but with the main emphasis on method 1 (because the event should be objectively identifiable), perhaps some reliance on method 2 (if there are cases where it makes sense to maintain incentives, within limits) and very little use of method 3 (because it imposes risk but offers little or no improvement in incentives).

The final outcome will require detailed consultation with the industry over the precise nature of the risks, incentives and decisions involved.

4.3. Treatment of Intermittent Generation

Intermittent generators are fundamentally different from conventional generators as they are typically energy constrained rather capacity constrained, i.e. their energy output is limited by

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15 The supposed rationale for this move is that capacity providers are best positioned to assess and quantity the drivers of their ability to provide capacity and therefore should be responsible for pricing it. However, this argument seems to overlook the potential benefits of insurance, if the costs of some outages within a portfolio of generation are borne by suppliers in general, rather than their individual owners.

16 See SEM Consultation, page 115.

the exogenously varying availability of an energy source (wind, tides, sun, etc) and by not the fixed capacity of the generator turbine. As a result, operators have much less control over the power that intermittent generators can provide at any point in time. For this reason there is an economic rationale for treating intermittent generation differently.

Any special treatment needs to be consistent with regard to rewards and penalties. If intermittent generators have no control over the amount of capacity they provide, they have a case for being exempt from the penalties for not providing capacity. However, if intermittent generators are unable to guarantee capacity during stress events, they also have no grounds for claiming any payment or reward for making capacity available.

In general, the de-rating factor applied to intermittent generators ought to divide their capacity into eligible capacity (which can take on ROs, but which is subject to penalties) and ineligible capacity (which has a zero value in MW throughout the RO scheme). Thus, a 100 MW wind farm with a 90% de-rating factor consists of 10 MW of eligible capacity (which is treated the same as any other capacity in the RO scheme) and 90 MW of ineligible capacity (which is ignored by the RO scheme).

We note that there are few reasons for completely exempting any capacity from penalties for low reliability, since that is one of the factors contributing to insecurity of supply and the need for operating reserves. Allowing unreliable generators to escape all the consequences of their choice of technology would provide an implicit subsidy to those who are imposing costs on others, although their liability for penalties need not be unbounded, for the reasons given above. The caps on penalties should take into account the unmanageable risks faced by intermittent generators and the need to mitigate the total financial burden of such risks. Promoting renewables sources of generation may be a policy objective, but economic efficiency demands that the capacity mechanism should not introduce unnecessary distortions into the choice of technology, by unduly favouring particularly unreliable sources of generation.

4.4. Conclusions

Rewards and penalties based on performance during times of system stress are the fundamental drivers than ensure the CRM solves the “missing money” problem. RO settlement gives capacity providers no additional incentive other than the market price, so they may lack the incentive to provide sufficient capacity. In such circumstances, CRMs must be bolstered by additional penalties and rewards for providing more or less physical capacity during periods of system stress.

These rewards and penalties need to be targeted to encourage efficient decisions without creating unnecessary risks. The availability of any capacity may be affected by both internal and external factors – i.e. factors that are within the control of the plant operators (like maintenance) and factors that are outside their control (like the level of wind). When availability depends on external factors, then imposing penalties on capacity providers offers no additional incentive, whilst the additional risk of penalties outside their control discourages capacity providers from building capacity and participating in the scheme.

For instance, many CRM schemes put a cap on total penalties over short periods, to limit their financial impact on capacity providers. Such caps mitigate the risk of bankruptcy, particularly for unmanageable external risks that market participants cannot unwind through offsetting hedges. By doing so, they help to encourage participation in the CRM and hence to produce a more efficient outcome overall.

The design of the CRM would benefit from industry input on the economic and financial parameters used to define and limit rewards and penalties for providing capacity, organised as a workstream on enforcement.

Appendix A. Italian Capacity Market Mechanism

The Italian Capacity Market Mechanism is a non-compulsory scheme for incentivising the provision of generation capacity. Capacity providers are given the opportunity to enter into Reliability Option (RO) contracts sold through annual competitive auctions. These contracts provide a fixed revenue stream to capacity providers to cover their fixed costs of making capacity available to the market. In exchange, capacity providers forego revenue received when reference prices are above the strike price of the RO contract they hold. RO contract strike prices are set on a regional basis with reference to the average variable cost of the marginal dispatched plant. Reference prices are also set regionally and therefore reflect the variations in system conditions across the network.

In order for a plant to be admissible into the capacity auctions it must not be intermittent, subject to any other type of investment incentive scheme or subject to any dismantling measures.[17] Prior to bidding into an auction Terna calculates an “expected available capacity” for each plant which provides an upper limit of the amount of capacity that can be bid into an auction for that plant.

A.1. References prices

The Italian Capacity Market Mechanism covers bidding into both the day-ahead market and the dispatch services market and therefore uses a scheme for setting the reference price which seeks to combine the prices from these two markets while maintaining the appropriate incentives for capacity provision. Table A.1 outlines how the reference price is determined based on the bidding behaviour and dispatch outcomes for a capacity provider in the day ahead and dispatch services market.

Table A.1
Bidding behaviour and determining the applicable reference price

Quantity		Spot price	
		Offered price ≤ strike price	Offered price > strike price
Accepted on the Day-ahead market		Price on the Day-ahead market (P_DAM)	
Presented but not accepted on the Day-ahead market (DAM) and not presented on the Dispatch Sevices Market (DSM) *or* Not presented on the DAM nor on the DSM	Adequacy system	Max (P_DAM; Max Price on the DSM)	
	Lack of adequacy system	VENF	
Presented and accepted on the DSM		Strike price	Offered price
Presented but not accepted on the DSM			Max (P_DAM; Max Price on the DSM)

Source: http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_12.pdf

The principle underpinning the design of the scheme is that capacity bid into a particular market should be settled against the price in that market. The scheme achieves this by

[17] Italian Capacity Market, Terna, Brussels, April 2015 http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_12.pdf

splitting the capacity under the RO contract according to which market each unit of capacity is bid into and is ultimately cleared. The quantity dispatched in the day-ahead market is settled against the day-ahead market price and then the quantity accepted in the Dispatch Services Market is settled against the Dispatch Services Market price. This split settlement process allows capacity providers to better manage their risks while still retaining the strong incentives associated with being exposed to the balancing market price. The remainder of this section summarises the incentive properties of potential outcomes under this split scheme.

In the circumstance where a capacity provider bids into the day-ahead market and their bid is accepted the reference price is set as equal to the day-ahead market price. In this case, a capacity provider is liable to repay the system operator when the day-ahead market price is greater than the RO contract strike price.

In the circumstance where a capacity provider does not bid into either the day-ahead or dispatch services markets or is not dispatched in the day ahead and then fails to bid into the dispatch services market then the applicable reference price depends on the prevailing system conditions.

If supply is adequate to meet demand then the reference price is equal to the maximum of the prices from the day ahead and dispatch services markets. In this circumstance, the capacity supplier is incentivised to bid into the market (either the day-ahead or dispatch services market) with the greatest likelihood of having a price that is greater than the contract strike price as this will minimise the likelihood of having to give a payment to the market operator. In other words, while ever there is a risk that the price in either market will exceed the contract strike price then a bidder is expected to bid into the market that values its capacity the highest. However, this exposes the generator to some basis risk, if its forecast of the market prices turns out to be the wrong way round.

If there is insufficient supply to meet demand - a so called ‘stress event’ - then the reference price is set to the Value of Energy Not Supplied (VENF). Under these conditions the price in the DSM is also set to VENF and so this is equivalent to settling the RO contract against the DSM price. In this case, since the VENF will always be greater than the contract strike price, the capacity provider is liable to pay the system operator the difference between the VENF and strike price. As the VENF is high relative to the strike price, the result of this pricing rule is that there is a very strong incentive to provide capacity during these stress events.

For capacity suppliers bidding into the dispatch services market, the applicable reference price is a function of both whether a bid was accepted or not and whether the price bid is greater than the strike price since the dispatch services market is pay-as-bid.

If the price offered into the dispatch services market is below the strike price then the reference price is set equal to the strike price (irrespective of whether the bid was accepted or not). The result being that no payment back to the system operator will ever be required under this circumstance. This is equivalent to making the RO a one-way or call option that uses the offer price as a reference price.

If the price of the bid offered is greater than the strike price, if the bid is accepted then the reference price is equal to the bid price. In this case, a capacity supplier is liable to pay the difference between their bid and the strike price and therefore may have a reduced incentive to bid above their short run costs of providing balancing/ancillary services. Finally, if the bid is not accepted then the reference price is set to the maximum of the prices in the day ahead and ancillary services markets. Since the bid was not been accepted on the DSM, the bid must have been higher than the DSM price, and highly likely to have been higher than the day-ahead market price.

A.2. Auctions for Reliability Option contracts

The RO contracts are expected to be issued through annual auctions administered by Terna. The scheme provides three separate ways for capacity supplier's to obtain RO contracts, namely:

- Main Yearly Auction
- Adjustment auction
- Secondary Market

The main yearly auction is for the procurement of capacity four years ahead of delivery and for a delivery period of three years. The auction is run as a multi-round descending auction with the aim of issuing the contracts at the lowest possible price, as determined by the market. It is expected that the bulk of contracts will be issued through the main yearly auction.

The adjustment auction is an opportunity for capacity suppliers to adjust their position from the main yearly auction between 1 and 3 years in advance of the delivery year. It will also be conducted through a multi-round descending price auction. There is also expected to be an active secondary market whereby capacity suppliers can adjust their contract positions held through trades of one month contracts with other market participants. These transactions are expected to be conducted on an ongoing basis within a year of capacity delivery.

Owing to the significance of interconnector constraints in the Italian market, RO contracts will be issued on a regional basis through separate auctions. Capacity requirements vary greatly by region and so the value of capacity and therefore strike prices must vary to provide non-distortive price signals. The implementation of separate auctions reduces the level of competition in each regional auction and therefore potentially increases the likelihood that capacity providers have a degree of market power in procuring RO contracts.

A.3. Financial hedging considerations

The complex mix of the day-ahead market price and dispatch services market prices in determining the reference price raises questions around the ability for market participants to appropriately hedge their financial exposure to the wholesale electricity price. The applicable reference price is largely determined by the behaviour of the bidder and which market they choose to bid into and therefore, bidders retain some control around which market prices they are exposed to through the capacity mechanism. Therefore, to a large degree the scheme design allows bidders to manage their financial exposure through traditional products based on either the day-ahead or dispatch services market prices.

Appendix B. New England Capacity Market Mechanism

The ISO New England Forward Capacity Market (FCM) operates on the basis of a Capacity Supply Obligation (CSO), which is analogous to the concept of Reliability Obligations. Capacity Supply Obligations are allocated through auction processes known as the Forward Capacity Auctions (FCAs) and capacity providers receive payments equal to the price set through the auctions.

The FCM is currently undergoing reform with respect to the mechanism for incentivising the provision of capacity by capacity providers. The current scheme has come under criticism for not providing the appropriate incentives and so the ISO-NE over recent years has developed a number of amendments to the current scheme. Together these proposed changes are known as the pay-for-performance scheme. The current scheme and the proposed pay-for-performance scheme are discussed in the next section.

The FCAs occur every year and are used to allocate CSOs to capacity providers through a competitive process. Within the FCAs there is a mechanism for ensuring that capacity market meets the need of all regions of the network. To do this the network is split into import constrained zones, export constrained zones and the rest of the pool based on the supply, demand and transmission characteristics of areas within the network. These regions are reassessed periodically to take account of changing market conditions. For example, two zones were recently added for the FCA-10 to be held in 2016.[18] In import constrained zones, a local sourcing requirement is specified which is a minimum amount of capacity that must be procured in that zone. In export constrained zones a maximum capacity requirement is incorporated in the auction clearing mechanism.

B.1. The Current and Proposed Capacity Market Incentive Mechanisms

ISO-NE is in a transition period with respect to its capacity market performance incentive arrangement. In February 2014, ISO-NE's proposed reforms to the capacity market, known as the pay-for-performance scheme, were brought before the Federal Energy Regulatory Commission (FERC) for approval. After revisions these new provisions were successfully passed through and are to be incorporated into the terms of the CSO's allocated from FCA-10, which will be held in February 2016.[19]

In its submissions to the FERC, ISO-NE claim that the previous FCM mechanism was not producing the appropriate incentives for capacity provision and this was leading to reduced performance of the fleet of generators in ISO-NE.[20] In particular, the numerous exemptions

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[18] ISO New England Inc., Docket No. ER15-___-000; Identification of Potential New Capacity Zone Boundaries, 6th April 2015, http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13830206

[19] Master Forward Capacity Auction #10 Schedule, February 2015, http://www.iso-ne.com/markets/othrmkts_data/fcm/auction_cal/2019_2020_master_fwrd_cap_auction_10.pdf

[20] ISO New England Inc. and New England Power Pool, Filings of Performance Incentives Market Rule Changes; Docket No. ER14- -000 , http://www.cramton.umd.edu/papers2010-2014/er14-1050_000_1-17-14_pay_for_performace_part_1.pdf

from penalties, the fact that entering into a CSO did not involve any risk of negative payments and that the definition of scarcity conditions were triggered only after 30 minutes of scarcity meant that insufficient investment was being made in capacity and plant flexibility, leading to increased outages.

The ISO-NE proposed pay-for performance scheme separates the capacity market mechanism into two stages. The first stage is similar to the current auction process and involves the procurement of capacity to meet the expected load through the allocation of CSOs through the FCAs. The second stage involves performance payments based on whether a generator is providing capacity during a capacity shortage period, as defined over a 5 minute interval. These performance payments only involve transfers among participants; from capacity providers that are generating during the capacity shortage events to providers who are not. It also eliminates the many exemptions from penalties that previously applied, and therefore places sharper incentives on capacity providers irrespective of prevailing conditions.

For FCA-9 and previous auctions the scheme included a provision for Peak Energy Rent (PER). PER is payment back to the system in circumstances where the market prices exceed a defined strike price and therefore works in a similar manner to the payment profile under the Reliability Obligation. The ISO-NE has developed a further reform proposal to eliminate this PER as it is no longer required with the implementation of the Pay-for-Performance scheme as the scheme will provide sufficient incentives.[21] This change is expected to be implemented from FCA-10 onwards. Previously, the PER adjustment has been criticised for being a poor and incomplete hedge for energy purchasers and does not protect load against spiking fuel costs.

B.2. Load Following Obligations in New England

The Pay-for-performance incentivises performance through the calculation of performance payments which vary in accordance with the system conditions. These payments are calculated using the following formulae[22]:

$$Performance\ Payment\ = Performance\ Payment\ Rate\ x\ Performance\ Score$$

$$Performance\ Score = Actual\ MW - CSO\ x\ Balancing\ Ratio\ (in\ \%)$$

$$Balancing\ Ratio\ (in\ \%) = \frac{\sum(Load + Reserve\ Requirement)}{\sum Capacity\ Obligations}$$

A key parameter for determining the strength of these incentives is the Performance Payment Rate. ISO-NE calculates the rate based on the Cost of New Entry and intends to phase in the rate as follows:

- $2,000/MWh for the period 1 June 2018 to 31 May 2021;

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21 Peak Energy Rent (PER) Adjustment Mechanism - Proposal for FCA-10 and Beyond, February 2015

22 FCM Performance White Paper, October 2012, http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf

- $3,500/MWh for the period 1 June 2021 to 31 May 2024; and
- $5,455/MWh for the open-ended period starting 1 June 2024.

ISO-NE states that these capacity Performance Payment Rate is designed to achieve its loss-of-load probability standard of "one day in ten years", which is equivalent to about 2.4 hours of lost load per year on average.

Through these formulae, the payments under the pay for performance scheme vary according to the prevailing system conditions through the balancing ratio. The balancing ratio is defined as the ratio of the total capacity requirement (ie, the sum of total load and reserve requirement) to the total capacity obligations allocated. Therefore, at times of high demand, the total capacity requirement increases and consequently, so does the balancing ratio. This increase in the balancing ratio effectively increases the share of the CSO that is compared to the actual capacity provision when calculating the performance score and therefore decreases performance payments when supply is plentiful and increases payments when supply is scarce.

The pay-for-performance scheme creates particularly strong incentives for capacity providers to meet their obligations by limiting the scope to avoid penalties for under-provision. The scheme puts a cap on negative payments, but does not rule them out entirely, so participation is no longer a zero-cost option.

The lack of exemptions means that capacity provider must cost all of the risks that may cause them to fail to meet a capacity obligation into the bids in the capacity auction. These include risks associated with events outside the control of the capacity provider, such as being constrained off due to transmission outage.

B.3. Treatment of Intermittent Resources in ISO New England

In the ISO-NE market, intermittent resources are allowed to bid into the capacity market auctions and are able to acquire Capacity Supply Obligation contracts in essentially the same manner as a conventional generator. However, in contrast to conventional generators, it is optional for intermittent resources to bid into the day-ahead market.[23] In assessing the capacity that can be bid into the FCAs the performance of the wind farm is taken into account and therefore a capacity significantly lower than the nameplate capacity is applied.

Under the current rules, intermittent generation is subject to the Peak Energy Rent adjustment where payments are made back to the system operators for revenues earned during periods of high prices. However, it is not subject to any further penalties for not providing capacity during peak events.

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[23] Benefits/Risks of Having Capacity Supply Obligation (CSO), October 2014, http://iso-ne.com/static-assets/documents/2014/11/12_fcm101_oct_2014_capacity_supply_obligations.pdf

One of the key principles underlying the pay-for-performance scheme is that in contrast to the existing rules there are no exemptions[24] and therefore, under the proposed pay-for-performance scheme intermittent generators, such as wind or solar, are treated in the same manner with regards to their performance payments as any other generation resource. Respondents to the FERC assessment of the pay-for-performance scheme[25] argued that, because intermittent resources such as wind and solar are "predictably variable", then they can forecast the overall performance of these resources. Further, since intermittent resources are only allowed to bid a fraction of their nameplate capacity into the FCAs they can potentially exceed their CSO and attain positive performance payments.

24 ISO New England Inc., and New England Power Pool, Filings of Market Rule Changes To Implement Pay For Performance in the Forward Capacity Market, Jan 2014, http://www.cramton.umd.edu/papers2010-2014/er14-1050_000_1-17-14_pay_for_performace_part_1.pdf

25 Order on Tariff Filing and Instituting Section 206 Proceeding, Paragraph 79, http://www.iso-ne.com/regulatory/ferc/orders/2014/may/er14-1050-000_5-30-14_pay_for_performance_order.pdf

Appendix C. Incentives Under a Blended Market Reference Price

This appendix presents a theoretical example based on section 3.6.22 of the I-SEM consultation document. We show that the blended reference price can provide muted incentives through providing a marginal price to capacity providers that is less than the balancing market price.

Consider the circumstance similar to that defined in the example in section 3.6.22. A capacity provider has not bid its full capacity into the day-ahead market as it believed that the expected price was lower than its short run marginal cost (SRMC) for some of its capacity, at least. A network outage has occurred and so the balancing market price is now expected to be higher than their SRMC and so the capacity provider plans on bidding into the balancing market.

We first define the revenue equation for a generator under a blended market reference price:

$$Revenue = P_D . Q_D + P_B . Q_B - \max\left[\left[\left(\frac{Q_D}{Q_D + Q_B} . P_D + \frac{Q_B}{Q_D + Q_B} . P_B\right) - S_P\right], 0\right] . Q_R$$

where P_D, P_B are the prices in the day ahead and balancing markets respectively and Q_D, Q_B, Q_R are the quantities of capacity offered into the day-ahead market and balancing market and the quantity under the Reliability Obligation, respectively. S_P is the RO strike price. As in the Italian example, the relative weights of each market are specific to each capacity provider.

To find the marginal effect on revenue of the generator offering additional output into the balancing market we calculate the derivative with respect to Q_B, the quantity offered into the balancing market. This gives:

$$\frac{\partial R}{\partial Q_B} = P_B - \frac{Q_R Q_D (P_B - P_D)}{(Q_D + Q_B)^2}$$

In the example $P_B > P_D$ and so if we assume that the RO is called:

$$Q_R > 0$$

$$Q_D > 0$$

$$\left(\frac{Q_D}{Q_D + Q_B} . P_D + \frac{Q_B}{Q_D + Q_B} . P_B\right) > S_P$$

we get a positive deduction from P_B on the right hand side, and so:

$$\frac{\partial R}{\partial Q_B} < P_B$$

This result shows that under the blended market reference price approach, when a rebate is being paid, the additional revenue received from offering an additional unit of capacity into the balancing market is less than the balancing market price. The additional unit of capacity both increases the revenues from the wholesale market and shifts the reference price by changing the relative weights applied to the day-ahead and balancing markets.

For example, let $P_B = €300/MWh$, $P_D = €150/MWh$, $Q_D = 40$, $Q_B = 25$, $Q_R = 80$. Assume that the RO is called and a rebate is being paid (if, as the RAs do, we assume $\mathrm{S_P} = €200/\mathrm{MWh}$ then this will be the case). The revenue received for an additional unit of capacity is then less than the Balancing Market price, being given by the following formula:

$$300 - \frac{80 \text{ x } 40 \text{ x } 150}{65^2} = €186/MWh$$

This muted incentive only occurs in a scenario where a RO rebate payment is made. With a higher strike price the significance of this disincentive declines, as events where the MRP is greater than the strike price are less frequent.

Appendix D. Contracting and Basis Risk

This Appendix provides a formal description of financial flows under the RO and the implications of a scenario where trading and RO settlement occur in different markets.

In the case shown in **Box 1**, the reference price is the DAM price and the generator trades its total output in the DAM (incurring no imbalance charges). This example does not create any basis risk because the Market Reference Price for ROs is the same as the wholesale price paid or received by market participants. The CFD between the generator and supplier includes a provision whereby the difference payment is defined by the difference between the *contract strike price (C)* and the *DAM price (D)* only when D is less than or equal to the RO strike price (S), as shown in the top half of **Box 1**. When D rises above S during periods of system stress, as in the lower half of **Box 1**, the difference payment is defined by the difference between the *contract strike price (C)* and *the RO strike price (S)*.[26]

Box 1: Financial Flows under an RO and CFD per MWh

C = CFD Strike Price **D = Day-ahead Price**
S = RO Strike Price

Price Case		Generator	TSO	Supplier
D ≤ S				
	Spot Mkt. Payments	D		-D
	CFD Diff. Payments	C - D		D - C
	Net Flows	C	0	-C
D > S				
	Spot Mkt. Payments	D		-D
	CFD Diff. Payments	C - S		S - C
	RO Diff. Payments	S - D	D - S	
	RO Pass-through		S - D	D - S
	Net Flows	C	0	-C

This adjustment to the CFD contract is required so that difference payments under the CFD are aligned with the actual revenue from the wholesale market net of the difference payment under the RO. In addition, as discussed in the SEM Consultation[27], the generator's RO difference payment to the TSO must be passed through the supplier to avoid imposing an unhedgeable risk on the supplier. Without these adjustments, the net payment from supplier

[26] The latter outcome can be achieved either by redefining the net difference payment in the CFD, or by the buyer giving the seller a call option with a strike price equal to S, the strike price in the RO. The CFD then imposes a difference payment of C-D on the seller, while the option awards the seller D-S, leaving the seller a net payment of C-S.

[27] See SEM Consultation, Section 3.1.4

to generator during periods of system stress would not be the fixed CFD strike price (C), but rather a more variable amount, namely: C+S – D.

Box 2 shows another, extreme, scenario where a generator sells all of its output into the Day-Ahead Market at the DAM price (D), but the MRP is the price in the Balancing Market (B). When the RO is exercised, as in the middle section of **Box 2**, a basis risk emerges that is equal to the difference between the DAM price and the BM price (i.e. equal to D-B).

Box 2: Financial Flows under an RO and CFD – Selling at a different price from the MRP and the effect of a modified CFD

C = CFD Strike Price **D = Day-ahead Price**
S = RO Strike Price **B = Balancing Price**

Price Scenario		Generator	TSO	Supplier
B ≤ S				
	Spot	D		-D
	CFD	C - D		D – C
	Net Flows	C	0	-C
B > S				
	Spot	D		-D
	CFD	C - S		S - C
	RO Transfer	S - B	B - S	
	RO Pass-through		S - B	B - S
	Net Flows	C + (D-B)	0	-C - (D-B)
Modified CFD				
B > S				
	Spot	D		-D
	Modified CFD	C - S - (D-B)		S - C + (D-B)
	RO Transfer	S - B	B - S	
	RO Pass-through		S - B	B - S
	Net Flows	C	0	-C

Specifically, when the balancing price is higher than the day-ahead price (i.e. D-B < 0), as would be expected during an unexpected transmission network outage, the capacity provider's net revenue falls. This variation in revenue represents a problem for risk management by generators and suppliers alike.

In a circumstance where trading in the DAM is compulsory, adjustments to CFDs could account for the risk associated with exposure to the difference between prices in the Day-Ahead and Balancing Markets. As with the adjustment to the CFD to account for the RO payment, market participants could adjust their contracts to allow a generator to pass through to a supplier the difference between the day-ahead and balancing market prices. A the bottom of **Box 2** we provide an example of the adjustments to a CFD contract necessary to ensure that market participants effectively manage their risk in a scenario where the market rules force market participants to trade in the DAM and the MRP is the BM. We have termed this the 'modified CFD' approach.

A more likely outcome is described in **Box 3** (which echoes **Box 1** with the BM price replacing the DAM price). In this scenario, trading by the generator and supplier has moved to the BM and CFD contracts are now struck against the BM price. This shift from the DAM to the BM eliminates the basis risk that occurs when the strike price is called as there is now no exposure between the price differential between the two markets.

Box 3: Financial Flows under an RO and CFD per MWh – MRP from BM

C = CFD Strike Price **B = Balancing Market Price**
S = RO Strike Price

Price Case		**Generator**	**TSO**	**Supplier**
B ≤ S				
	Spot Mkt. Payments	B		-B
	CFD Diff. Payments	C – B		B - C
	Net Flows	C	0	-C
B > S				
	Spot Mkt. Payments	B		-B
	CFD Diff. Payments	C - S		S - C
	RO Diff. Payments	S - B	B - S	
	RO Pass-through		S - B	B - S
	Net Flows	C	0	-C

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