Integrated Single Electricity Market (I-SEM)

High Level Design for Ireland and Northern Ireland from 2016

Draft Decision Paper

(SEM-14-045)

Power NI's Response

25th July 2014

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Executive Summary

Power NI welcomes the opportunity to respond to the Draft Decision Paper (SEM-14-045) published by the Regulatory Authorities (RAs) in relation to the High Level Design for the Integrated Single Electricity Market (I-SEM).

The changes to the current wholesale electricity trading arrangements contemplated by this work programme represent the most significant change to the electricity industry since the implementation of the Single Electricity Market (SEM) in 2007 and Power NI remains committed to actively engaging with the RAs through the design and implementation phases of this project.

The RAs should be cognisant that given the 2016 deadline this project is on the critical path. Compressed timetables have, in previous major market projects, led to a shortening of the design phase and a compression of the implementation and testing phases. This represents a significant risk to the market and its participants.

Given such time pressure and that there has been a series of delays at European level in the completion of the relevant codes Power NI would welcome the RAs revisiting the project plan, revising the timeframes and fully considering all options.

In such planning it is important to recognise that suppliers endeavour to hedge a proportion of volumes significantly in advance i.e. 12 to 18 months. Such a requirement means that the forwards market for the I-SEM needs to be operational in mid to late 2015. This should be an important consideration in the RAs planning. Information and decisions taken must align accordingly to ensure that this takes place in an efficient and effective manner.

In defining the high level design of the I-SEM, the RAs must be cognisant of their statutory duty to protect consumers. Only the largest of commercial customers are realistically in a position to dynamically interact with the market place. All small and medium enterprises and domestic customers' source, and will likely continue to source, their electricity needs via a supplier. Even mindful of the aspirational goals of smart metering and demand side participation, the overwhelming demand from customers is, and will continue to be, a requirement to have certainty and consistency in electricity pricing.

To deliver this requirement, suppliers must offer fixed, non-volatile tariffs that can be easily presented. Simplicity in market design is key to customer engagement. To this end it is imperative that suppliers are able to hedge the majority of volume in the forwards market to ensure tariff stability, cognisant that the price in the forwards market is the price consumers pay. It is therefore crucial that any design has a properly functioning forwards market in terms of volume, price and flexibility i.e. liquid.

There is a pre-conception that liquidity is simply volume; this is not the case. Liquidity refers to availability of hedges based upon a competitive price formation, covering a variety of timeframes at times when there is demand to buy them, not purely when generators choose to sell.

Liquid and transparent forward markets enable suppliers to hedge efficiently; they shield consumers from volatile spot markets and facilitate competitive tariff structures. Effective forward markets also provide open access to mitigate market power and concentration, and send price signals to drive investment. The effective functioning of a forwards market is therefore vital for competition and consumer choice.

When considering the theoretical aspects of the market design therefore, it would be incorrect to assume that by ensuring a strong day ahead price this would in isolation provide such a robust reference price that it will encourage forward liquidity. The current SEM offers an absolutely clear reference price for the entire market however the SEM suffers from a chronic lack of liquidity in the forward market.

While the RAs have acknowledged the issue of liquidity in the forwards market, Power NI is concerned that considering measures to deal with the issue appears to be an activity the RAs will undertake in parallel with the detailed design. Power NI believes that the market design must foster a liquid forward market or risks repeating the failures of the SEM design. Consideration of forward liquidity should therefore be a central design aspect rather than a parallel activity.

Generator participants will undoubtedly highlight to the RAs the issue of schedule and volume risk; exposure to such risk will undoubtedly reduce participation in the forwards market. The prevention of physically forward trades coupled with the indication that the DAM will not necessarily be mandatory for all generation undermines its usefulness as a reference price in the forwards market.

Without careful consideration of the practical operation of the market the RAs are proposing individual design decisions without taking a holistic view of how the market will work. Such an approach cannot deliver a wholesale market which serves customers effectively.

It would appear that one unavoidable aspect of the use of EUPHEMIA is the increase in scope for generators to manage their costs via their bidding approach. While theoretically this may facilitate more active competition Power NI has concerns that this level of complexity may result in a premium being applied across the generator community. It must also surely reduce the level of transparency in the market. Power NI would welcome further careful consideration being given to this area by the RAs.

The balancing market is also of critical importance to suppliers. Suppliers will be subject to forecasting risk; this is unavoidable and it would be contrary to the principles of equity if the balancing costs for such imbalance are punitive. As the costs will ultimately be borne by consumers the RAs should ensure that balancing risk to suppliers remains equitable.

While the RAs have also acknowledged the importance of the balancing market, insufficient detail has been provided at this stage. Similarly to the question of forward liquidity, actions and assessment appear to have been deferred to the detailed design. This represents a significant risk to suppliers and Power NI believes the RAs must provide more detail in relation to both areas. Without such detail it is impossible to adequately assess, critique or understand the implications of the proposed high level design decision.

Power NI believes that market power mitigation was not effectively considered in the design of the SEM with Directed Contracts being mandated relatively late in the process and no consideration given to the forwards market and whether it would operate effectively. To fail to consider this issue in the design phase of the I-SEM repeats a fundamental SEM design flaw which has pushed scarcity premiums to end consumers.

In considering such an issue it is a risk to the project design to push the analysis to the detailed design; akin to the liquidity considerations a holistic view must be taken and not isolated design decisions.

The implementation of the SEM significantly increased the collateral requirements placed upon suppliers. Pool exposure accompanied by hedging activities has required suppliers to have in place high value letters of credit or cash deposits. This collateral requirement is a burden on suppliers, requires financing, potentially acts as a barrier to entry and the associated costs ultimately appear in a customers bill.

Power NI believes that the I-SEM should look wherever possible to minimise the collateral requirements to a reasonable level. Participation in the market should be encouraged and the costs minimised, therefore preventing barriers to entry.

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.

Energy price volatility is not in the interests of consumers who value price stability in end tariffs.

Without substantially greater detail it is difficult to fully comment on the methodology chosen. In not choosing a methodology which includes a supplier obligation Power NI considers that the RAs have avoided unnecessary participation costs. It is unclear however how a supplier will interact with this solution and how the settlement will take place. Power NI recommends a solution which could be socialised across the market thereby reducing volatility, aiding transparency and avoiding unnecessary supplier participation costs.

Introduction

The changes to the current wholesale electricity trading arrangements contemplated by this work programme represent the most significant change to the electricity industry since the implementation of the SEM in 2007.

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 considered the high level design requirements, assessed the options presented and now comments on the Draft Decision Paper.

The 2016 deadline for I-SEM implementation remains a significant challenge for the RAs and market participants. Power NI believes that this current round of engagement and consultation has been worthwhile. Power NI also welcomes the Regulatory Impact Assessment published in conjunction with the Draft Decision Paper.

The RAs should remain cognisant however that given the 2016 deadline this project is now on the critical path. Such time pressure should however not prompt the RAs to negate due process in thoroughly assessing both the high level and detailed design of the market. Compressed timetables have in previous major market projects led to a shortening of the design phase and a compression of the implementation and testing phases. This represents a significant risk to the market and its participants.

General Comments

The RAs, within the recently published paper, made four high level decisions in relation to –

1. I-SEM Energy Trading Arrangements
2. The I-SEM will include a CRM
3. The CRM will be quantity based, and
4. The CRM will feature Reliability Options.

Before considering the draft decisions made by the RAs and given the volume and diverse nature of responses to the earlier consultation, it may be useful to recap the key considerations Power NI has in relation to market design.

To support this Viridian engaged NERA Economic Consulting to provide expert analysis and a review if the RAs Draft Decision Paper. The Full paper is included in Appendix A.

Contained within the NERA paper is a considered review of the approach, criteria and consequences of the decisions proposed in the RAS paper. The paper covers both the practical and financial impacts of the proposals. Power NI would in particular, like to take this opportunity to highlight to the RAs the sections in relation to Energy Market Arrangements and Market Power Mitigation. Power NI would welcome the RAs giving this report careful consideration.

Power NI's key considerations

- **Risk Management and Liquidity**

When considering the high level design, the key aspects of the market from a supplier's perspective are the ability afforded by the market structure to manage risk, hedge exposure in the forwards market and the inherent liquidity which facilitates such activity. This requirement speaks directly to the efficiency, competition and equity assessment criteria.

As a stand alone, non-vertically integrated supplier, Power NI is concerned that the market structure could further reduce available hedging and risk management opportunities. The pricing regimes in any balancing, day ahead or intra day market must not inhibit participation in the forward market. Consumers and therefore suppliers desire price certainty. Securing volumes in quantities over and above a refinement level in later markets may add a risk premium if sufficient liquidity is not available to all supply participants. Given the size and nature of the Irish market, simple risk management opportunities should be available either through market structures or via regulatory mandate.

Power NI believes that the questions surrounding practicality, participation and risk management opportunities for suppliers must be addressed by the RAs. The differing effects of potential pricing algorithms, the operation of power exchanges and the practicalities of trading arrangements will all determine the effectiveness of the market.

Liquid, transparent and competitive forward markets enable suppliers to hedge efficiently; they shield consumers from volatile spot markets and facilitate competitive tariff structures. Effective forward markets also provide open access to mitigate market power and concentration, and send price signals to drive investment. The effective functioning of a forward markets is therefore vital for competition and consumer choice.

Liquidity is a term which has been used extensively throughout the high level design considerations and draft decision. Dependent upon a participant's perspective however, liquidity is important in different timeframes.

There is a pre-conception that liquidity is simply volume; this is not the case. Liquidity refers to availability of hedges based upon a competitive price formation, covering a variety of timeframes at times when there is demand to buy them, not purely when generators choose to sell.

The RAs have a statutory duty to protect consumers. Only the largest of commercial customers are realistically in a position to dynamically interact with the market place. All small and medium enterprises and domestic customers' source, and will likely continue to source, their electricity needs via a supplier. Even mindful of the aspirational goals of smart metering and demand side participation, the over whelming demand from customers is and will continue to be a requirement to have certainty and consistency in electricity pricing.

To deliver this requirement, suppliers must offer fixed non-volatile tariffs that can be easily presented. To this end it is imperative that suppliers are able to hedge the majority of volume in the forwards market to ensure tariff stability, cognisant that the price in the forwards market is the price consumers pay. It is therefore crucial that any design has a properly functioning forwards market in terms of volume, price and flexibility i.e. liquid.

This customer requirement has been clearly demonstrated both in Northern Ireland when domestic customer tariffs were reduced in 2012 then increased in 2013, and the current political pressure in the UK to freeze prices. Such certainty can only be delivered if a supplier is able to hedge long term exposure via contracts available in a liquid forwards market.

The forwards market in the current SEM suffers from a number of significant deficiencies. There is a high level of demand for a wide range of hedges but a distinct lack of products being offered and traded. Power NI welcomes the RAs acknowledgement that "the SEM has not been successful in developing a forward hedging contracts market." The reform of the wholesale market affords the RAs an opportunity to address the detrimental aspects of the current market and move towards a properly functioning market across all of the timeframes.

The issues with the forwards market today include -

- Lack of volume,
- Infrequent nature of auctions,
- Lack of transparency,
- Market dominance,
- Inexplicable price spreads,
- Scarcity premiums,
- Market exit (some financial players have exited the European commodities market following the implementation of EMIR e.g. Deutsche Bank, Bank of America/Merrill Lynch and JP Morgan)

Power NI firmly believes that these issues have lead to an inefficient, uneconomic forwards market that is placing a price premium on domestic and small/medium enterprise customers.

While the RAs have acknowledged the issue of liquidity in the forwards market, Power NI is concerned that considering measures to deal with the issue appears to be an activity the RAs will undertake in parallel with the detailed design. Power NI believes that the market design must foster a liquid forward market or risks repeating the failures of the SEM design. Consideration of forward liquidity should therefore be a central design aspect rather than a parallel activity. The commitment made in Section 6.4.6 to "*establish a workstream to investigate forward liquidity-promoting measures in the forwards energy markets*." falls significantly short of what is required for suppliers and does not provide any assurance that customers are at the heart of the RAs decision making.

An additional and important consideration for Power NI is the operation of the balancing market. Suppliers will be subject to forecasting risk; this is unavoidable and it would be contrary to the principles of equity if the balancing costs for such imbalance are punitive. As the costs will ultimately be borne by consumers the RAs should ensure that balancing risk to suppliers remains equitable.

While the RAs have also acknowledged the importance of balancing market insufficient detail has been provided at this stage and similarly to the question of forward liquidity actions and assessment appears to have been deferred to the detailed design. This represents a significant risk to suppliers and Power NI believes the RAs must provide more detail in relation to both areas. Without such detail it is impossible to adequately assess, critique or understand the implications of the proposed high level deign decision.

- **Financeability and stability**

The implementation of the SEM significantly increased the collateral requirements placed upon suppliers. Pool exposure accompanied by hedging activities has required suppliers to have in place high value letters of credit or cash deposits. This collateral requirement is a burden on suppliers, requires financing, potentially acts as a barrier to entry and the associated costs ultimately appear in an end users bill.

Power NI believes that the I-SEM should look wherever possible to minimise the collateral requirements to a reasonable level. Participation in the market should be encouraged and the costs minimised.

Equally of concern to participants who trade in Sterling is the currency exposure. Mandatory participation in markets linked via Euphemia will likely settle in Euro. This creates currency risk, potential currency hedging requirements and further collateral requirements on Sterling participants. This is an asymmetrical risk placed on certain participants in an inequitable manner.

Draft Decision 1 - I-SEM Energy Trading Arrangements

Power NI is disappointed that the RAs have not addressed the key issues for suppliers in their proposed decision.

Forwards Market

In proposing an option which facilitated self-scheduling Power NI sought to deal with the issue of generator scheduling risk which ultimately has resulted in the ineffective forwards market witnessed in todays SEM.

As stated above, Power NI welcomes the RAs acknowledgement of the issue of liquidity in the forwards market; Power NI is however very concerned that considering measures to deal with the issue appears to be an activity the RAs will undertake in parallel with the detailed design.

Statements such as in Section 5.6.4 that "The new trading arrangements should support the strong development of retail competition, which will drive innovation and liquidity" suggest that the RAs believe that a liquid forward market will naturally evolve. Power NI believes that the market design must specifically foster a liquid forward market or risk repeating the failures of the SEM design. Consideration of forward liquidity should therefore be a central design aspect rather than a parallel activity.

Option 3 aims to increase liquidity by focusing on the DAM which is beneficial for effective market coupling. This however does not secure liquidity in the forwards market, which is the overarching requirement of suppliers and customers. As described above, price stability and predictability are key mass market customer requirements which can only be met by an efficient forwards market.

Under Option 3, much akin to the SEM, generators will not know until close to real time if they will be in the merit order. As with today, such uncertainty tends to drive a lack of forward liquidity.

Generator participants will undoubtedly highlight to the RAs the issue of schedule and volume risk; exposure to such risk will undoubtedly reduce participation in the forwards market. The indication that the DAM will not necessarily be mandatory for all generation also potentially weakens the Day-ahead price outcome which again further undermines its usefulness as a reference price in the forwards market.

Without careful consideration of the practical operation of the market the RAs are proposing individual design decisions without taking a holistic view of how the market will work.

Option 1 provided some potential benefits to the Irish market which should be recognised; specifically within the contract market. Should generator participants be able to self-schedule, then providing forward contract liquidity will provide running certainty. This would stimulate the forwards market

Power NI acknowledged that option 1 suffered from potential market power issues. The characteristics of the Irish market are such that market power mitigation will be a requirement regardless of the solution chosen and the RAs have acknowledged this in the Draft Decision. Power NI continues to believe that market maker obligations and/or self-supply restrictions on certain players would ensure that the market operates effectively across all of the time frames. Such intervention would ensure that all participants; suppliers, thermal and renewable generators can operate effectively in the market.

By ruling out the possibility of self-scheduling the RAs are proposing a solution which will have inherent volume and scheduling risk for generation participants which will in turn adversely affect suppliers and ultimately customers. It is critical that these issues are dealt with at the high level design phase and this may require the RAS to adopt a more interventionist strategy to ensure that all market timescales are efficient and the optimal outcome is achieved.

Day Ahead Market

Power NI supports the high level intention of ensuring a DAM which provides robust pricing signals and delivers an efficient market schedule. It is unclear however why the RAs have concluded that this cannot be achieved if the forwards market is physically firm. It is equally unclear how this market will deliver such outcomes if parties are not required to participate. Without further detail there is a risk that such a decision will weaken the reference price, create a price premium for suppliers in the DAM (due to shortages) and push suppliers further into the intra day and balancing markets which theoretically are supposed to be used for refinement of position not primary trading.

Without further detail it is impossible to fully assess the implications of the proposal within the Draft Decision. While the RAs acknowledge this as an issue (Section 6.4.23) Power NI would welcome the RAs providing significantly greater detail prior to locking in any irreversible decisions.

Within Power NI's response to the High Level Design Consultation Paper, some reservations about EUPHEMIA acting as the market solver at a European level were raised. Power NI welcomes the RAs recognition of this issue and the further investigations undertaken. While reservations remain, robust end to end testing will be required and a sustained period of market trials would be a welcome aspect of the project plan.

It would appear that one unavoidable aspect of the use of EUPHEMIA is the increase in scope for generators to manage their costs via their bidding approach. While theoretically this may facilitate more active competition Power NI has concerns that this level of complexity may result in a premium being applied across the generator community. It must also surely reduce the level of transparency in the market. Power NI would welcome further careful consideration being given to this area by the RAs.

Additionally, Power NI would like to take this opportunity to once again highlight that with most of the trading focussing on the DAM; there will be significant credit and cash flow implications for the day-to-day operation of a supply business. Credit would have to be placed to cover the extent that forward trades are possible. Credit would also be required to be posted with the market place for the entire supplier volume traded through the DAM. A supplier seeking to hedge in the forwards market would also be covering the same proportion again with the NEMO, plus the residual. This significantly increases the participation cost for suppliers.

It is also likely that the DAM will settle significantly earlier than the current SEM and potentially in Euro. While this might offset some of the credit requirements, the working capital facilities required would be substantially in excess of today's requirements. Such a requirement is an onerous burden on suppliers; it increases cost and requires significant financing. This represents both a major issue to current suppliers and potentially creates a barrier to new supplier entry.

This option also heightens the currency exposure a Sterling participant is likely to be exposed to. Such an exposure is likely to prompt a requirement to hedge currency which in turn requires additional supplier collateral further increasing the cost of participation in the market.

While the RAs have acknowledged collateral costs as an issue it also appears to have been deferred to the detailed design phase and has not been a consideration for the high level design. This is a concern for all suppliers.

Intra Day Market

In ruling out the opportunity to secure physical trades in the forwards market and weakening the DAM (by reducing the volume potentially traded); the Draft Decision implies that there will be significant volumes of trades undertaken in the intra day timeframe.

While this may facilitate renewable generation output, akin to the DAM considerations, it is unclear how smaller participants will be actively trading and the interaction with the priority dispatch requirement.

It also represents an inefficient outcome for suppliers. As stated previously an inability to secure volume in the forwards market coupled with a weaker and potentially punitive DAM forces Suppliers into the intra day market for significant volumes. This outcome both increases the complexity and risk which a supplier faces.

Balancing Market

The level of information provided in relation to the balancing market is of concern. Suppliers will inevitably be exposed to the balancing market to some degree. Inherent forecasting risk is compounded by the apportionment of the residual error in the marketplace. This will be exclusively a balancing cost to a supplier.

Statements in the Draft Decision proposing marginal pricing, pay as bid and merit orders begin to explain what participation may look like, however the paper remains at too high a level for in depth commentary.

A lack of volume or an inability to secure volume in the earlier markets heighten suppliers anxiety in regards to the balancing market and Power NI would urge the RAs to give greater consideration to the proposed operation of such a market and provide that information as soon as possible to participants.

Market Power Mitigation

In the response to the High Level Design consultation Power NI highlighted that, at a philosophical level the RAs may be inclined to consider the market design in isolation and allow the market to deal with issues of power and dominance in an evolutionary or theoretical manner. Power NI strongly advised against proceeding to a high level design decision without detailed consideration of the market power mitigation options available. It is disappointing that the RAs appear to have postponed consideration of the strategy until the detailed design phase.

Given both the size of the Irish market and the players within it, along with the chunky nature (in terms of relative size) of the generation units and the interconnection available, to fail to consider market power mitigation fully could represent a fundamental failure by the RAs, result in a sub-optimal design and be contrary to the RAs statutory duty to protect consumers.

Power NI believes that market power mitigation was not effectively considered in the design of the SEM with Directed Contracts being mandated relatively late in the process and no real consideration given to the forwards market and whether it would operate effectively. To fail to consider this issue in the design phase of the I-SEM repeats a fundamental SEM design flaw which has pushed scarcity premiums to end consumers.

A liquid day-ahead market is not necessarily a driver for a liquid forward market without further intervention. This is particularly the case where there is a high degree of vertical integration.

When considering the theoretical aspects of the market design therefore, it would be incorrect to assume that by ensuring a strong day ahead price (such as via Option 3) this would provide such a robust reference price that it will encourage forward liquidity. The current SEM offers an absolutely clear reference price for the entire market however the SEM suffers from a chronic lack of liquidity.

The Bidding Code of Practice provides transparency and confidence in the out turned market prices. Relaxation of such principles as suggested in the Draft Decision is instinctively of concern to suppliers as transparency will be reduced. The wholesale market in Ireland is both small in scale and has major structural and dominance issues. Relaxation of current controls, an absence of tailored measures coupled with the asymmetry of information and options available to dominant players, will not ensure effective or efficient market outcomes.

The Draft Decision document highlights the potential for competition through interconnectors to weaken the market power of dominant players, once these are fully integrated into the market arrangements. This may be true, but only to the extent that there is not a concentration of Financial Transmission Rights (FTRs) amongst the dominant players in the I-SEM. Some form of maximum capacity holdings may be considered to mitigate this risk. This requirement may also be enhanced given that a number of the Irish players have a significant presence in the UK market and therefore may have the ability to exercise market power by virtue of their interconnected integration.

Draft Decision 2 - The I-SEM will include a CRM; Draft Decision 3 - The CRM will be quantity based, and Draft Decision 4 - The CRM will feature Reliability Options

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.

Energy price volatility is not in the interests of consumers who value price stability in end tariffs.

Without substantially greater detail it is difficult to fully comment on the methodology chosen. In not choosing a methodology which includes a supplier obligation Power NI considers that the RAs have avoided unnecessary participation costs. It is unclear however how a supplier will interact with the proposed solution and how the settlement will take place. Power NI recommends a solution which could be socialised across the market thereby reducing volatility, aiding transparency and avoiding unnecessary supplier participation costs.

The solution should also seek to avoid unnecessary collateral costs and large introductory funding payments. Aspects such as these will act as a barrier to entry in the supply market. At present the information available appears to be focussed on the generator perspective of a capacity mechanism. While ensuring capacity, encouraging flexibility and providing clear entry and exit signals are all critical aspects of any CRM design; it is of equal importance to understand and ensure that end customers are not unreasonably affected by a CRM and that suppliers can interact with a CRM effectively.

As stated in Power NI's earlier response; in general terms, a level of intervention is not of particular concern as it should assist in the targeting of flexible generation assets; TSO procurement therefore appears appropriate.

Of particular concern is the lack of information on how the RAs envisage the capacity market interacting with the energy market. Capacity is an important aspect of generator financeability. The volume and strike price secured by generating units will influence positions adopted in the energy market; as will the physical implications of constraints and expected running arrangements.

Conclusion

In consideration of the key design aspects of the I-SEM, Power NI believes there are a number of fundamental areas the RAs must be cognisant of.

Power NI has summarised these key, fundamentals as –

- The I-SEM project is under significant time pressure if it is to meet the 2016 deadline.
- Establishing an effective, efficient and liquid forwards market is absolutely critical as this drives the ultimate price paid by the majority of consumers.
- Market power mitigation must be considered as a high level design consideration.
- Generator financeability is important and in the long term interests of the market and its customers.

In developing the Draft Decision Paper the RAs have identified the key design areas. The paper does however push significant areas of consideration to the detailed design phase. In relation to the energy market significant further work, explanation and analysis is required to understand the implications of the proposals; including how the CRM proposal will impact the energy trading actions of participants. Without such a holistic view it is unclear as to whether the proposed decision meets the assessment criteria.

The RAs appear to have ruled out physically firm trades in the forwards market which would ensure forward liquidity and yet have deferred proposing alternative measures to secure such a vital aspect of the market to the detailed design.

Likewise in relation to the mandatory nature of the DAM the RAs have suggested that this may not be mandatory for all participants yet not described what the potential consequences of such a decision may be for the other market windows.

Power NI welcomes and supports the high level principles of the market. Efficient and competitive wholesale markets are crucial in ensuring the end consumers are protected. Suppliers must be able to participate in an effective manner; complex and difficult solutions will create avoidable costs ultimately paid by consumers. Power NI would welcome the RAs providing significantly greater levels of practical information as the process moves towards a detailed design phase.

Ultimately the cost of establishing and running the new market will be paid by end consumers. Overwhelmingly end consumers seek price stability which can only be effectively delivered by an efficient forwards market supplemented by day ahead and intra day markets which facilitate refinement of positions and a balancing market which is not punitive. At this stage in the design Power NI, mindful of the RAs statutory duties, would have expected that the Draft Decision to speak directly to this target model. By deferring design decisions to the detailed design phase it is impossible to assess if customers are going to be protected in the I-SEM.

Also absent from the Draft Decision Paper was any discussion or consideration of transitional arrangements. In moving from the SEM to the I-SEM the RAs should consider the impact on both suppliers and generators. Generators will understandably be concerned about changes to investment signals which have been relied upon and suppliers need to understand how costs will change and what potential exposures will be faced.

It is also important to recognise that suppliers endeavour to hedge a proportion of volumes significantly in advance i.e. 12 to 18 months. Such a requirement means that the forwards market for the I-SEM needs to be operational in mid to late 2015. This should be an important consideration in the RAs planning. Information and decisions taken must align accordingly to ensure that this takes place in an efficient and effective manner.

Appendix 1 – NERA Report entitled I-SEM Draft Decision SEM-14-045: A Review

NERA
ECONOMIC CONSULTING

I-SEM Draft Decision SEM-14-045: A Review

Prepared for Viridian

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Executive Summary

Viridian has asked us to comment on the SEM Committee's Draft Decision Paper (DDP) and the associated Initial Impact Assessment (IIA) on a High Level Design for the new "Integrated Single Electricity Market" (I-SEM).

Viridian asked us specifically to assess the soundness of the proposed decision on the High Level Design for the I-SEM. Viridian also asked us to identify any potential areas of concern over the supporting rationale provided by the SEM Committee for its draft decision and to identify areas of the market design that require significant further clarification during the detailed design phase. Our instructions cover the "Options" for trading energy as well as the "Capacity Remuneration Mechanisms" (CRMs).

In reviewing the DDP and IIA, we found problems in the quality of argumentation, the application of appraisal criteria and the descriptive evidence used to support the appraisal. The SEM Committee's appraisal is, as a result, subjective, selective and biased. It does not provide a proper basis for selecting an electricity market design and no-one can have any confidence that the SEM Committee has reached the right decision on a High Level Design for the I-SEM. We conclude that the SEM Committee's decision is unsound. We have indicated how these problems may be addressed in the final decision.

Quality of Argumentation

We found that our task of reviewing the DDP and the IIA was hampered by the poor quality of the argumentation in those documents.

The appraisal criteria adopted by the SEM Committee are defined in vague terms, interpreted subjectively and applied selectively. On occasion, the appraisal seems to turn on unstated criteria, such as "liquidity". We have therefore proposed a set of more practical appraisal criteria. Arguments used in relation to one possible design (i.e. to one Option or one CRM) were not applied equally to other possible designs, causing the evaluation to be incomplete and selective. We have pointed out where this problem arises. The categorisation of different schemes (particularly the CRMs) contains errors that bias the eventual selection. We have provided correct information where it might affect the appraisal.

Focus on Trade Rather than Dispatch

The most serious problem with the SEM Committee's appraisal of Options and CRMs lies in a mis-specification of the proposed reform's overall objective.

Discussion of the new electricity market, the I-SEM, has been prompted by the desire to promote "market coupling", i.e. to improve the SEM's integration with the British electricity market. Market coupling is an initiative running throughout the EU to facilitate cross-border trade in electricity. Its objective is to increase the efficiency with which capacity, including both supply-side and demand-side resources, is dispatched at a European level, in order to reduce costs and increase efficiency.

The authors of the DDP and the IIA appear to have lost sight of this objective. The appraisal of the Options and CRMs gives very little attention to their effect on the efficiency of the intra-day and real-time process of *dispatch* or to actual outcomes for generation and consumption. Instead, it focuses on promoting *trade* within the day-ahead institutions used for market coupling. In other words, the DDP and IIA give undue weight to the prospects for a *derivative* product (trading in day-ahead electricity contracts), instead of considering the impact of proposals on the *underlying commodity* (electricity generated and consumed).

This focus on trading rather than dispatch distorts the appraisal of market designs and prejudices the SEM Committee's selection of a preferred Option. It is possible to remedy this deficiency in the final decision and impact assessment as we explain.

Appraisal of Options for Energy Trading

The "Qualitative Appraisal" set out in the IIA provides no objective or balanced support for the SEM Committee's draft decision. Gaps in the definition of the chosen Option and its potential effects are significant enough to affect the SEM Committee's appraisal. More analysis is required to ensure that the chosen Option meets the criteria of efficient market design. In the meantime, the SEM Committee's appraisal is selective and prejudiced, rendering its decision unreliable.

The chosen Option relies on a trading algorithm, Euphemia. The SEM Committee assumes that it will produce an efficient pattern of output in the day-ahead market, but it may not, given the lack of detail on intra-day and real-time institutions. These institutions may allow the TSO to restore an efficient pattern of generation, but inefficiency in the day-ahead market will raise costs and prices to consumers. Moreover, the SEM Committee has not addressed the problem of volume/scheduling risk. The discussion of interconnectors contains several errors and does not fully consider alternative contract forms. In relation to the liquidity of forward markets, the assessment does not compare the Options on a level playing field, but adopts varying criteria which favour some Options over others on an *ad hoc* basis.

The appraisal of the proposed Options is therefore incomplete, subjective and prejudiced. As a result, the conclusions reached in the DDP must be considered unsound.

Appraisal of Capacity Remuneration Mechanisms

The appraisal of CRMs suffers from many of the same flaws as the appraisal of energy trading options. The problems begin with the creation of a false dichotomy between "price based" and "quantity based" schemes. Most relevant examples include a demand curve – an explicit trade-off between price and quantity – and so do not fall within either category. (The same trade-off is implicit in other schemes.) The advantages and disadvantages that the appraisal assigns to each CRM according to whether it is "price based" or "quantity based" are therefore spurious.

When deciding in favour of Reliability Options, the SEM Committee repeatedly describes them as "market based", and marks down other schemes for requiring regulatory interventions. This approach overlooks practical examples and academic literature on the design of Reliability Options. Experience and theory both indicate that the payments to providers of capacity under Reliability Options should be linked to the provision of physical capacity (not just energy). Reliability Options therefore require regulatory intervention, to decide what capacity is provided by each resource and how to penalise resources that fail to deliver it. The SEM Committee defers discussion of such topics until the detailed design phase. However, it cannot properly compare Reliability Options with other CRMs in the high level design phase without taking these requirements into account.

The appraisal of CRMs is therefore incomplete, because the SEM Committee left out significant details from the proposed design of the Reliability Options. We also found the appraisal to be selective, because it overlooks possible adverse effects of the proposed scheme. In any case, the overall appraisal was biased by the use of criteria that varied from case to case, preventing like-for-like evaluation of the designs. Due to these flaws in its appraisal, the SEM Committee's choice of one particular CRM is not soundly based.

Consideration of Market Power Mitigation

The consideration of measures to mitigate market power is equally selective. The SEM Committee has chosen Option 3, even though it will make the BCOP unworkable. It does not offer any alternative measures. This difficulty ought to have counted against Option 3, relative to Options 2 and 4, but the DDP simply defers the problem to the detailed design stage. Market power remains a problem, so any completely specified Option would include alternatives to the BCOP, such as an increase in the volume of directed contracts.

In relation to CRMs, the SEM Committee adopts different views in the DDP from those expressed in the IIA. The DDP repeatedly describes Reliability Options as "market-based" and implies that the process of awarding and managing them will be solved by transparent auctions with little need for regulatory intervention. The IIA, on the other hand, notes that conduct of an auction will require major regulatory intervention to mitigate market power. These conflicting approaches betray a fundamental confusion about the implications of Reliability Options for competition.

Overall, the SEM Committee's approach to the mitigation of market power is subjective and prejudicial. It is neither evidence-based nor a sound basis for regulatory decisions.

Consequences for the Consumer

The choice of electricity market design has long term implications for consumers. Inefficiency and scheduling risk in the Day Ahead Market will raise costs and prices of electricity, even if the TSO can restore an efficient pattern of generation through intra-day and real-time trading. Incompletely specified CRMs will leave consumers exposed to the risk of under-investment in capacity. Given the long term nature of these implications, it would be undesirable to commit to a High Level Design before considering all its effects.

Conclusions

We found many problems in the quality of the appraisal used to justify the SEM Committee's choice of Option 3 and Reliability Options. In particular, we found areas where the appraisal is subjective, selective and biased, with the effect that the discussions are prejudicial and do not provide a proper basis for selecting an electricity market design, putting the Decision at risk of legal challenge. We conclude that the SEM Committee's decision is unsound and that market participants cannot be confident that the SEM Committee has reached the right decision on a High Level Design for the I-SEM.

1. Introduction

1. Viridian has asked us to comment on the Draft Decision Paper (DDP) and the associated Initial Impact Assessment (IIA) issued by the SEM Committee on 9 June 2014 on the subject of the High Level Design for the new "Integrated Single Electricity Market" (I-SEM).[1]

2. Viridian asked us specifically to assess the soundness of the proposed decision on the High Level Design for the whole of the I-SEM, comprising both energy trading arrangements ("Options") and the Capacity Remuneration Mechanism (CRM). Viridian also asked us to identify any potential areas of concern over the supporting rationale provided by the SEM Committee for its draft decision on the High Level Design and to identify areas of the market design that require significant further clarification during the detailed design phase.

3. Rather than provide a line-by-line response to the SEM Committee's documents, we comment below on the quality of the arguments used in the DDP and IIA and on the SEM Committee's general approach to appraisal. We have taken this approach because we found many of the arguments in the documents to be poorly drafted, as explained in chapter2, for reasons that affect the documents as a whole, namely:

   - the Options and CRMs set out in the DDP and IIA are incomplete, with the result that it is not possible to appraise or compare them rationally and objectively. The DDP is intended to meet the requirements of the EU Target Model, which are dominated by a desire to facilitate cross-border trading, but that has led to the neglect of other – potentially more important – aspects of market design;
   - the DDP and the IIA apply design criteria in a selective and subjective manner, using vaguely expressed arguments that are sometimes prejudiced in favour of one particular Option (i.e. Option 3) or on particular CRM (i.e. a form of "Reliability Option").

4. In section 2.2, we clarify how these deficiencies could be remedied in the final decision. In chapters 3 and 4, we describe the problems with the draft decision, using examples from the documents themselves. These problems imply that the conclusions reached in the draft decision are not robust or soundly based. We provide more detailed comments on the arguments used in the DDP and the IIA in chapters 5 (Energy Market Arrangements), 6 (Capacity Remuneration Mechanism) and 7 (Market Power Mitigation), and in related appendices. Chapter 8 collects together all our conclusions.

[1] SEM Committee (2014a), Integrated Single Electricity Market (I-SEM): High Level Design for Ireland and Northern Ireland from 2016: Draft Decision Paper, SEM-14-045, 9 June 2014 ("DDP"); and SEM Committee (2014b), Integrated Single Electricity Market (I-SEM): High Level Design for Ireland and Northern Ireland from 2016: Draft Decision on HLD for I-SEM: Initial Impact Assessment, SEM-14-046, June 2014 ("IIA").

2. Quality of Argumentation

5. The DDP states early on that "The SEM Committee is committed to evidence based decision making".[2] We applaud this sentiment, as regulatory decisions have long term implications for investment, for costs and for the prices paid by consumers. As long as the regulatory process is open to the submission of evidence by all interested parties, and such submissions are subject to scrutiny and challenge by others, regulators will have the best available evidence to hand. Making decisions based on evidence then minimises the potential for actions that are subjective, arbitrary or politically-motivated and hence not in consumers' interests.

6. In the current context, we expected to see an Initial Impact Assessment which provided a complete (if high level) description of each alternative electricity market design, and which applied a fixed set of appraisal criteria to each design, as neutrally and objectively as possible, to identify which design best meets consumers' needs. Such an IIA would have provided robust support for an "evidence based decision". The reality has proven to be disappointing. The lack of detailed reasoning places an unnecessary obstacle in the path of external scrutiny through an analytical review of the evidence.

2.1. Problems with the SEM Committee's Current Approach

7. The approach adopted by the SEM Committee in the DDP and the IIA creates a number of problems for external scrutiny.

8. First, the various possible designs for energy trading arrangements ("Options") and CRMs are not completely specified, or else different designs are specified in terms that overlap and prevent proper comparisons.

   - The descriptions of Options for energy trading focus on short-term markets (and day-ahead markets in particular), but neglect many of the real-time institutions (balancing and imbalance pricing). These omissions make it impossible to appraise the impact of each Option on actual outputs, demand, pricing and the efficiency of outcomes.
   - The description of CRMs makes a false distinction between "price based" and "quantity based" schemes, since in practice many schemes involve a trade-off between price and quantity – either explicitly (a "demand curve") or implicitly (through occasional revisions to scheme parameters). The description of Reliability Options (the favoured form of CRM) varies between a narrow definition (which excludes CRMs that are called Reliability Options in other countries) and a broad definition (which includes CRMs that would also count as "price based" or "quantity based").

9. These incomplete or variable definitions of different designs make it difficult to distinguish between the merits of different schemes. They also allow those carrying out the appraisal to pick and choose what (positive and/or negative) characteristics to assign to each market design. The result is a highly subjective and prejudicial review of each of the designs, which

[2] DDP, page 4.

appears to be aimed at justifying the selection of Option 3 and Reliability Options, instead of identifying the market design best suited to the I-SEM.

10. Second, the appraisal criteria used in the IIA and reflected in the DDP are defined in terms that can only be evaluated subjectively. The IIA then applies them selectively, or in conjunction with further unstated criteria, so that the market designs are not appraised on a level playing field. The result is that the SEM Committee's appraisal method gives every appearance of being biased in favour of a prior decision to select Option 3 and Reliability Options.

11. Third, some of the arguments set out in the IIA and DDP are demonstrably incorrect or non-sequiturs. For instance, the IIA considers the point that the auction price for Reliability Options will not cover the "missing money" if it is not backed up by rules on the physical definition of capacity and penalties for under-performance. It responds that this problem might arise if the RO market were purely voluntary, but will not arise "if the purchase of reliability options to cover total system requirements is mandatory".[3] We found this response rather surprising, since there is no basis in observation or analysis for such an assertion. We are therefore not convinced that the SEM Committee's impact assessment has been carried out thoroughly, taking account of the academic literature on this topic. (See section 6.1 below.)

12. It is difficult for third parties to engage with an appraisal that is subjective, selective and seemingly biased, and applied to market designs that are incompletely defined. External observers cannot know precisely what factors influenced the draft decision, or what further evidence would affect the final decision. All that can be concluded is that the draft decision is not "evidence based" in any proper sense, and is not objective, sound or reliable.

2.2. Requirements for the Next Stage

13. The next stage in the regulatory process is, technically, the production of a final decision. In that stage, any properly constituted Final Impact Assessment would have the following characteristics:

- Detailed descriptions of each market design which clearly identify (1) all the features that determine real world outcomes, and (2) all the features that distinguish one design from another;
- Appraisal criteria that are well defined and capable of objective measurement whenever possible;
- An appraisal process that applies the criteria equally to each market design (to the exclusion of other criteria);
- A neutral or even-handed evaluation of the market designs, covering all the appraisal criteria and noting any subjective or "qualitative" evaluations where they arise;

[3] IIA, paragraphs 7.5.26-27.

- A clear statement of the decision and the reasons for reaching it, drawn directly from the evaluation of market designs.

14. To produce a robust decision, the SEM Committee would have to meet all these requirements by the time of a final decision. We are conscious of the deadline for this decision, and our comments below are intended to fit with the proposed decision process. Should it not prove possible to resolve the outstanding difficulties in time, the SEM Committee would have either to postpone the final decision, or else to recognise that its decision is not robust and cannot be binding on the precise form of the I-SEM. Instead, its final decision would only be able to (1) recommend a market design as a starting point for further investigation, (2) list the matters to be investigated in detail, and (3) define the criteria for changing or adjusting the market design in the light of these investigations.

15. Equally importantly, the SEM Committee would need to adopt (and publicise) a procedure that allowed third parties to submit technical advice and to scrutinise all the work on a detailed design. The impact of market arrangements depends crucially on the details of their design and such scrutiny will be important to ensuring an efficient design for the SEM. The SEM Committee will in any case need to set up a procedure whereby the market designers and/or third parties can refer for adjudication (1) decisions to change (or not to change) the market design and (2) disputes over the detailed specification.

2.3. Conclusion

16. The arguments set out in the IIA are of very poor quality and do not support the decision process set out in the DDP. The descriptions of market designs are incomplete and not completely fixed or distinct, the appraisal is highly selective and subjective, and incorrect arguments are asserted without the support of observation or analysis.

17. We conclude that no-one can have any confidence that the SEM Committee has reached the right decision on High Level Design for the I-SEM.

18. In the following chapters, we identify the main deficiencies in the analysis produced so far and provide material that would help the SEM Committee reach a more soundly based decision.

3. Neglect of Real-Time Arrangements

19. We reviewed the sections in the DDP and the IIA that discuss energy market arrangements. In doing so, we identified a general flaw in the SEM Committee's approach that devalues the resulting conclusions.

20. The descriptions of each Option focus mainly on certain aspects of energy trading. This focus on trading seems to derive from the need for "market coupling" - primarily day-ahead – under the EU Target Model for the pan-European electricity market. Owing to this focus on day-ahead trading, the descriptions of each Option neglect the real-time arrangements for short-term trading and despatch that determine the final pattern of output and demand. This omission has serious implications for the appraisal of the Options and undermines confidence in the SEM Committee's conclusions.

21. In addition, the draft decision is based on an incomplete description of each Option and therefore of its impact on efficiency and security of supply. The lack of completely specified Options makes any appraisal difficult, if not impossible. In the context of the DDP, it means that the SEM Committee's appraisal of the Options does not consider all the relevant information and that its selection of Option 3 is not soundly based.

3.1. EU Target Model – Key Elements

22. The EU Target Model lies behind the SEM Committee's current proposal to change the way electricity is traded in the All-Island electricity market. In practice, it imposes relatively few requirements on the design of the electricity market itself, but does set out some requirements for cross-border trade, which the SEM does not meet at present.

23. The EU Target Model is set out most clearly in guidelines issued by ACER, particularly the *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity* ("CACM Guidelines") issued in 2011[4] and the *Framework Guidelines on Electricity Balancing* ("Balancing Guidelines") issued in September 2012.[5] Together, these and other guidelines set out the context for the current reform of the SEM. The key elements of these guidelines for the SEM Committee's work on a new High Level Design are as follows:

- **Market Coupling:** cross-border transmission capacity must be made available at the day-ahead stage all across Europe "implicitly" through trades arranged on power exchanges, rather than being explicitly auctioned.
- **Cross-Border Transmission Contracts:** to allow cross-border risk hedging, TSOs must auction off Financial Transmission Rights (FTRs) or Physical Transmission Rights (PTRs) to interconnector capacity. PTRs must be subject to Use-It-Or-Sell-It (UIOSI) provisions, making them similar in effect to FTRs.

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4 ACER (2011), *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, 29 July 2011.

5 ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012.

- **Gate Closure:** The CACM Guidelines provide for an intra-day market that enables market participants to trade energy as close to real-time as possible, through implicit auctions (trades on power exchanges that bundle together energy and any necessary cross-border transmission capacity) where feasible.
- **Balancing by TSOs:** TSOs in neighbouring countries must collaborate to pursue operational security, overall social welfare and efficiency: (1) by fostering competition, non-discrimination and transparency in balancing markets; (2) by facilitating the participation of demand response and renewable sources of energy; and (3) by promoting cross-border balancing exchanges.[6] More specifically, the Balancing Guidelines require TSOs to collaborate on achieving an efficient (i.e. least-cost) joint despatch across all systems,[7] which will require the TSOs to exploit all potential gains from trade (i.e. all opportunities for optimisation).

24. We set out more detail on these requirements in Appendix A.

25. The RAs have focused on day-ahead market coupling, with intra-day market coupling to follow in due course. According to the RAs,[8] day-ahead market coupling requires each electricity market to adopt the pan-European system – a single price-coupling algorithm ("Euphemia") that is approved by ENTSO-E; in addition, the RAs maintain that each TSO must submit all available cross border capacity to the operator of the cross-border market at the day-ahead stage. From our review of ACER's guidelines, it is not entirely clear how the RAs reached these conclusions. However, they seem to have guided the SEM Committee's appraisal of the various future "Options" for energy trading in the I-SEM. We would therefore expect the SEM Committee to explain the source of these conclusions in the Final Decision.

26. In any case, the desire to incorporate the I-SEM into the pan-European system has led to the SEM Committee focusing on day-ahead trading, rather than the actual outcomes for output and demand, as discussed below.

3.2. The Focus on Day-Ahead Trading

27. The appraisal set out in the DDP and backed up by the IIA focuses heavily on the design and role of the Day-Ahead Market (DAM), due to the emphasis on cross-border day-ahead trading in the EU Target Model. This focus on day-ahead trading has led the SEM Committee to neglect other aspects of electricity market design. The DDP and the IIA omit

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6 ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012, section 2.1, page 12.

7 "TSOs are responsible for organising balancing markets and shall strive for their integration, keeping the system in balance in the most efficient manner and following the general objectives defined in Section 2.1 of these Framework Guidelines. To do so, they shall work with each other in close cooperation and coordinate their activities as much as necessary.…the Network Code on Electricity Balancing shall define that exchanges of balancing energy are to be based on a TSO-TSO model with common merit order list. In this model, TSOs share their balancing resources and optimise their activation in order to minimise the cost of balancing..." ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012, sections 2.1 and 3.3.2, pages 12 and 17.

8 SEM Committee (2013), *Implementation of the European Target Model for the Single Electricity Market – Next Steps Decision Paper*, SEM/13/009, 15 February 2013, p18.

detailed descriptions of real-time market institutions, specifically: real-time despatch processes and *ex post* imbalance pricing. These real-time institutions play an important role in determining actual outcomes for output and demand, and hence for prices and investment. The design, role and impact of intra-day markets is also largely neglected in the DDP and IIA. Decisions on these institutions are left for the detailed design stage. Unfortunately, these omissions constrain and bias the SEM Committee's evaluation of Options for the I-SEM.

28. The institutions operating in real time (i.e. despatch and imbalance pricing) define how the I-SEM will organise and put a price on the "*underlying commodity*" – i.e. electricity generated and consumed. The intra-day and balancing markets provide the means by which market participants and the TSO react to changing circumstances, correcting any forecasting errors made at the day-ahead stage. All these aspects of the electricity market are crucial for achieving security of supply and efficiency in generation – both of which are important principles of electricity market design and criteria for appraising the Options. However, the DDP and IIA give very little attention to these crucial matters. Instead, they focus on the need for day-ahead trading, which is merely a market for *derivatives* of the underlying commodity.

29. This focus on derivatives, and the lack of attention to the underlying commodity, have distorted the SEM Committee's appraisal of the Options. The Options themselves are incompletely specified, and the SEM Committee reaches conclusions, based on considering the day-ahead market, that might be untrue or invalid if the SEM Committee had considered the system as a whole. In this chapter, we explain and illustrate these problems with the DDP and IIA. We show how the decision to select Option 3 is biased because it is not based on a full understanding of each Option's features or implications.

3.3. Incompleteness of the Market Designs

30. It is impossible to evaluate the performance of any Option without considering the real time institutions and their impact on the underlying commodity, in terms of security of supply and the efficiency of output, demand, pricing and investment in the electricity sector. The appraisal in the DDP and IIA rests on hidden assumptions about these other institutions. However, these hidden assumptions create inconsistencies within the appraisal of each Option and a bias in the comparisons between Options. We illustrate these inconsistencies and biases with two examples: (A) an example taken from the discussion of interconnectors; and (B) an example showing the effect of emphasising liquidity of markets rather than efficiency of actual outcomes.

3.3.1. Example (A): interconnector outcomes

31. The problem, caused by focusing on day-ahead trading, is well illustrated by the analysis of interconnector flows set out in section 5.4 of the IIA. That section contains a long discussion of the costs associated with inefficient use of interconnectors. It states the SEM Committee's view that Option 3 will increase "overall efficiency across both markets" (i.e. I-SEM and GB), because it integrates interconnectors into the Day-Ahead Market.[9] That reasoning is incorrect.

[9] IIA, paragraph 5.4.40.

32. Paragraph 6.3.44 of the DDP acknowledges that day-ahead trading over interconnectors is based on a forecast of the actual conditions that will apply on the following day. Trades arranged in the day-ahead market may therefore flow in the "wrong" direction, i.e. from a high-priced market to a low-priced market, if conditions change within the day. Efficient use of the interconnector does not therefore depend on the outcome of day-ahead trading, but rather on the mechanism for adjusting flows within each day.

33. The EU Target Model requires TSOs to collaborate on efficient cross-border balancing in real time. (See section 3.1 above.) Section 5.4 of the IIA examines the difference in cost between:

- efficient day-ahead trading (i.e. full use of day-ahead arbitrage opportunities between the I-SEM and Great Britain); and
- efficient use of interconnector capacity in real time (i.e. the actual pattern of output resulting from efficient despatch).

It finds that efficient intra-day adjustment of flows over interconnectors would produce cost savings with a net present value running into hundreds of millions of Euros.[10] These cost savings depend on the arrangements for adjusting interconnector flows *after* the day-ahead stage, not on the existence of a Day-Ahead Market. Such intra-day adjustments might be arranged (1) through renominations of actual flows by market participants, (2) through intra-day cross-border trades, or (3) through inter-TSO collaboration.

34. The finding that intra-day adjustments have major potential benefits should have led the SEM Committee to examine in detail how best to achieve an efficient cross-border despatch (starting from any portfolio of day-ahead trades). Instead, the SEM Committee has mainly considered each Option from the point of view of its contribution to day-ahead trading. This misplaced focus on day-ahead trading has distorted the SEM Committee's review of each Option and biased its draft decision.

3.3.2. Example (B): despatch outcomes

35. The DAM, ID and Balancing markets are described as "exclusive" methods of arranging for a generator to run. However, there is no analysis in the IIA to show whether these methods are sufficient to achieve an efficient outcome under Option 3. Specifically, paragraphs 5.4.54-57 of the IIA focus only on the *liquidity* of day-ahead and intra-day trading under each Option. This section omits any consideration of *despatch processes* (including balancing), and does not consider the efficiency of *actual outcomes*. The discussion of the effect on liquidity is highly subjective and partial.

36. Respondents to the consultation have expressed reservations about the ability of individual generators to use Euphemia for scheduling their plant. When appraising Option 3, the SEM Committee *assumes* that the DAM will produce a reasonably efficient pattern of output,

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10 Table 14 on page 43 of the IIA gives a NPV of cost savings due to efficient intra-day trading of €537 million for "base case A" and €190 million for "base case B".

interconnector flows and demand,[11] whilst recognising that some balancing interventions will still be needed.[12] However, the SEM Committee does not accord the other Options the same benefit of the doubt. Instead, it assumes that the other Options will produce less efficient day-ahead schedules, *without consideration of the later effect of intra-day markets or balancing*. This appraisal of Options is therefore selective and biased.

3.3.3. Effect on wider evaluation of Options

37. The focus on day-ahead cross-border trading and liquidity sets up an intrinsic bias in favour of any model with organised day-ahead and intra-day trading (i.e. Option 3), and against models with more emphasis on self-scheduling, centralised despatch or *ex post* pooling (i.e. Options 1, 2 and 4). The SEM Committee has not fully considered measures that would promote liquidity in any Option. However, even if the day-ahead and intra-day markets within Options 1, 2 and 4 are less liquid than in Option 3 (which the DDP rates as important), they may produce more efficient outcomes in terms of actual despatch and interconnector flows (which is more important for consumers in the long run). The SEM Committee overlooks this possibility.

3.3.4. Summary

38. We discuss examples here that show how an undue emphasis on trading (combined with a lack of clarity over real time and ex post institutions) led to the SEM Committee's appraisal in the DDP and IIA being unduly subjective and biased in favour of Option 3. The lack of detail about real-time and ex post institutions affects the SEM Committee's appraisal of all the so-called "high level designs".

39. We consider the question of efficient despatch and its link to the DAM in more detail in sections 5.3 and 5.4. We return to the SEM Committee's discussion of interconnectors further in section 5.5. We consider liquidity and efficiency further in section 5.6.

3.4. Conclusion

40. The SEM Committee has justified a reform of the SEM by accepting the immediate requirements of the EU Target Model. Specifically, the description of each Option focuses on the requirements for market-coupling, which the RAs have defined as more or less synonymous with day-ahead trading. However, day-ahead trading concerns a *derivative* product. The SEM Committee has neglected the intra-day and real-time institutions that determine actual output, demand and prices for the *underlying commodity*. The "High Level

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11 The assumption of an efficient outcome is intrinsic to the treatment of cross-border flows over interconnectors, as discussed above. Unless the DAM produces an efficient outcome for the I-SEM, there is no basis for claiming that it will also decide the direction of cross-border flows efficiently.

12 "As discussed previously, the SEM Committee considers that EUPHEMIA will be a robust and reliable means of developing an unconstrained day ahead schedule in I-SEM. The contracted volumes from EUPHEMIA are notified to market participants and the TSO with hourly granularity. A process will be required by which all hourly products from EUPHEMIA are converted into a more granular nomination profile, which the TSO can utilise for system dispatch, based on generator physical constraints, such as ramp rates. Further work is required to establish the respective roles of market participants and the TSO in this process." (DDP, paragraph 6.4.56)

Designs" being appraised in the DDP and IIA are therefore incomplete. The missing details are required to support any robust, objective appraisal.

41. The incomplete description of the Options undermines the value of the SEM Committee's appraisal. We conclude that the decision to select Option 3 is not based on a full understanding of its implications and is biased by the focus on a limited set of each Option's features. As we discuss in the next chapter, the SEM Committee's appraisal criteria failed to restrain or correct this bias. The SEM Committee's draft decision is therefore unsound.

42. It will not be possible to construct a new electricity market without considering real-time institutions. Given the lack of attention these matters have received in the high level design phase, resolving the outstanding questions will require significant work during the detailed design phase.[13] Experience to date suggests that this task cannot be awarded to an individual advisor, but that the process must provide scope for technical advice and external scrutiny from all interested parties.

[13] The detailed design phase may well bring to light aspects of the chosen Option that overturn the assumptions underpinning its selection. To ensure that the final design meets all the necessary criteria in the detailed design phase, the designers will need sufficient flexibility to allow radical amendment of the chosen Option, or even the adoption of a different Option (amended as appropriate). Similar findings apply to the SEM Committee's specification and evaluation of CRMs, which indicates a corresponding need to retain flexibility over their design in the next phase of the decision process, as we discuss in chapter 6.

4. Adopting Practical Appraisal Criteria

43. The DDP and the IIA (in particular) reach conclusions based on arguments that are not robust, correct or logical. Parts of the appraisals set out in these documents contain statements that simply cannot be assessed or even understood by third parties, because they are ambiguous, vague or subjective. Some of these problems derive from the lack of a detailed description for each Option (see chapter 3), but many of the weaknesses in the arguments derive from the use of vague or undefined appraisal criteria, as we illustrate below.

44. For instance, paragraph 5.6.9 of the Initial Impact Assessment says that "Option 2 does not fit naturally into existing types of balancing arrangements". This statement is meant to indicate a disadvantage of Option 2, but it is so vague as to be meaningless. EirGrid has said that it can operate securely with any of the Options,[14] so a supposed inability to "fit naturally" into balancing does not put security of supply at risk. There is no way to know what this statement means or how this statement affected the SEM Committee's choice, so it is impossible to check its validity.

45. Such vagueness arises partly from the unclear definitions (and/or variable definitions) of the assessment criteria set out by the SEM Committee. Those criteria seem to be intended to reflect the requirements of the EU Target Model, which we discuss in section 3.1 above and explain further in Appendix A. The SEM Committee has chosen to define appraisal criteria in very broad terms, which makes them open to many different interpretations, as discussed in section 4.1 below. The resulting flexibility allows the SEM Committee to interpret its criteria differently when appraising different Options and CRMs.

46. To eliminate this problem, it will be necessary to define appraisal criteria less ambiguously. In section 4.2, and in more detail in Appendix B, we show how such criteria can be defined.

4.1. The SEM Committee's Assessment Criteria

47. The IIA lists the criteria used to assess the various electricity market designs (i.e. the energy trading Options and Capacity Remuneration Mechanisms), dividing them into primary criteria (driven by legal requirements) and secondary criteria (standard principles of regulation),[15] although the distinction does not appear to affect their use in the IIA and DDP. The SEM Committee sets out its appraisal criteria as follows:

- Primary
  - Internal Energy Market
  - Security of Supply
  - Competition
  - Environmental; and
  - Equity

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14 IIA, paragraph 5.6.24.

15 IIA, paragraphs 1.2.5-1.2.6.

- Secondary
  - Adaptive
  - Stability
  - Efficiency
  - Practicality

48. There appears to be a problem with the application of these appraisal criteria. As discussed above, the current reforms are driven largely by the requirements of the Internal Energy Market, and the desire to implement the EU Target Model. (See section 3.1.) The SEM Committee has therefore focused on the requirement in that model for day-ahead cross-border trading. That focus appears to have led the SEM Committee to apply some of the criteria (especially efficiency and security of supply) predominantly to the operations of the day-ahead market. A full appraisal would instead have considered the implications for these criteria of outcomes of the whole system, i.e. both trading by market participants and real-time despatch by TSOs.

49. Indeed, the SEM Committee's appraisal seems to be unduly weighted towards the creation of a "liquid" day-ahead market, even though the DDP and IIA do not list "liquidity" as an explicit appraisal criterion. This *ad hoc* focus on liquidity substitutes on occasion for proper consideration of the impact of different Options on electricity sector operations overall. For instance, as we show in section 3.3.1, the analysis of flows over the interconnector considers the efficiency of day-ahead *arbitrage* between neighbouring markets, but not the efficiency of real-time *generation and consumption*. This tendency has biased the appraisal of the different Options.

50. Without conducting a full appraisal, it is difficult to say whether addressing the bias in the SEM Committee's initial appraisal would change its decision. However, the SEM Committee is recommending a new system to market participants and RAs based on an appraisal that does not take into account all the implications for generators, consumers and the RAs themselves. The SEM Committee's application of its assessment criteria does not therefore provide a sound basis for reaching a decision based on all the relevant evidence.

4.2. Practical Design Criteria

51. In Appendix B, we list an alternative set of design criteria for electricity markets (i.e.energy trading and capacity remuneration), drawing on the economic principles of efficient market operation in a sector characterised by long-lived investment. These criteria capture objectives listed in documents supporting the EU Target Model – specifically the CACM Guidelines and the Balancing Guidelines. They also correspond to the primary and secondary assessment criteria of the SEM Committee. However, they provide a more precise, objective and practical basis for assessing different electricity market designs than the SEM Committee's own appraisal criteria.

52. Some of the correspondences between our criteria and the SEM Committee's criteria require explanation.

- First, the need to meet the requirements of the EU Target Model within the Internal Energy Market lies outside economic criteria. We have therefore omitted it from our list, but we take it as the basic motivation for the current reforms.
- Second, economic efficiency is a broad term which encompasses many other criteria, not least environmental concerns (known to economists as "internalising an externality"). We therefore only refer to environmental aims separately from efficiency, where renewable energy policy raises specific concerns.
- Third, we have not included any criterion corresponding to the SEM Committee's desire for "practicality", as we intend this whole list to provide a more practical guide to electricity market design.

53. Our design criteria are divided into three sub-sets: (1) those that apply to the overall architecture of the market infrastructure, i.e. to the whole set of markets in which electricity is bought and sold; (2) those that apply to the design of individual markets; and (3) those that apply to measures for mitigating market power. A well-designed electricity market will meet all the criteria in all three sub-sets. In some cases, failing to meet one criterion might be justified by better performance on another criterion. However, only meeting all the design criteria will ensure that electricity markets produce efficient outcomes that benefit consumers. We derive and explain our criteria in Appendix B, below.

4.2.1. Market Infrastructure

54. We begin by setting out practical design criteria reflecting the economic principles that apply to the design of the overall system (with the corresponding "primary and secondary principles" of the SEM Committee shown in square brackets):

(1) Market design must permit secure operation of the system by the TSO, so that generation always matches demand. [**security of supply**]

(2) Market pricing rules (in conjunction with any capacity remuneration mechanism) must allow total generation capacity that is efficiently selected (investment) and operated (despatch) to recover its costs. [**efficiency/environmental**]

(3) "Gate closure", i.e. the time when central despatch and administrative pricing take over from decentralised contracts and trading, should occur at the latest possible stage before delivery. [**security of supply, competition, efficiency/environmental**]

55. Two further principles arise as corollaries to the desire to attract efficient investment:

(4) The market design should allow traders at all times (1) to maintain a contract portfolio that hedges the price of their expected output, and (2) to change their contract position if their expected output changes. [**efficiency/environmental**]

(5) The electricity market infrastructure, the format of offer/bid prices and market pricing rules should allow non-discriminatory access by all generation and DSR technologies. [c**ompetition, equity, efficiency/environmental**]

4.2.2. Market Organisation

56. Any individual electricity market must also meet the following criteria:

(6) The market or despatch algorithm should select offers (and bids) in an efficient least-cost "merit order". [**efficiency/environmental**]

(7) Prices should reflect marginal costs in the geographic market concerned, i.e.: (1) the "system marginal cost" for markets covering the whole system; (2) the "local marginal cost" of individual generators operating within a local market (e.g. for generators that are "constrained on" or "constrained off" and running out of merit). [**efficiency**]

(8) Prices should reflect marginal costs over the timescale of decisions associated with trading in the market concerned. [**efficiency**]

(9) Pricing rules should offer market participants the assurance that:

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- generators will generate whenever the price is above their marginal costs;
- generators will not generate if the price is below their marginal costs;
- generators will receive a price above their marginal costs when they generate; and
- equivalent rules apply to the acceptance of offers submitted to markets;

(10) equivalent (but obverse) rules apply to the supply of, and bids from, despatchable DSR. [**efficiency**]

(11) Price-setting rules should be transparent (i.e. they should use objective data in pre-defined formulae). [**efficiency, stability, adaptive**]

4.2.3. Market Power

57. The DDP and IIA recognise the need for measures to mitigate market power in markets for energy and capacity. Competition policy is a complex matter, but any measures adopted to mitigate market power should meet the following criteria to avoid undermining the performance of electricity markets by other criteria, particularly the efficiency of investment and operations.

(12) Measures to mitigate market power should be transparent (i.e. use objective data in pre-defined procedures). [**competition, efficiency, stability, adaptive**]

(13) The existence of market power in one market should not preclude competitive entry or supply of services in a related market. [**competition, efficiency**]

4.3. Conclusion

58. Much of the argumentation in the DDP and IIA is weak, vague, selective or subjective. Some of the appraisals appear to be incomplete and hence prejudicial. We attribute this problem to the lack of clarity in the definition of the SEM Committee's appraisal criteria.

59. We also note that a focus on the EU Target Model has given the appraisal an undue emphasis on efficient arbitrage in individual markets, and on trading in contract derivatives, instead of focusing on the efficiency of generation and consumption of electricity, the underlying commodity. See chapter 3.

60. Electricity markets serve a role in helping market participants to make decisions about production and consumption, and so contribute to achieving the high level aims of efficiency

and security of supply. However, it would be wrong to focus on the performance of any individual market or markets as a final objective of electricity market design. Above, therefore, we have set out practical design criteria that focus attention on the ultimate outcomes, i.e. the actual outcomes for the generation and consumption of electricity that determine costs and prices, security of supply and economic efficiency.

61. Markets and trading provide a form of social organisation which is useful when it achieves certain objectives. However, the creation of a liquid market is not an objective in itself. It is therefore a mistake to abandon other objectives in the cause of promoting "liquidity". Unfortunately, the SEM Committee appears to have done just that. Our restatement of the appraisal criteria provides a better basis for assessing the Options and the role of individual markets.

62. With regard to the various CRMs, the SEM Committee placed great emphasis on the desirability of "market based" institutions, favouring Reliability Options for that reason. However, the SEM Committee does not define "market based" or explain how this term relates to the appraisal criteria set out in the IIA. Moreover, Reliability Options only appear to be "market based" becasuse they are incompletely specified in the IIA and DDP, certain regulatory requirements having been overlooked.

63. In summary, the SEM Committee has listed appraisal criteria that are vague and open to a wide range of interpretations. The DDP and the IIA apply other, unstated criteria such as "liquidity". Overall, we conclude:

- that the SEM Committee's appraisal of the Options and Capacity Remuneration Mechanisms is not based on equal application of objectively defined criteria, but on the selective use of subjectively defined criteria and *ad hoc* considerations; and
- that the SEM Committee's decision is therefore unsound.

5. Energy Market Arrangements

64. As discussed above, the descriptions of the Options for energy trading are incomplete, whilst the appraisal criteria used by the SEM Committee are defined vaguely and applied in a selective manner. These conditions are not conducive to a thorough and objective appraisal of the Options. Indeed, as might be expected, we found several problems with the appraisal set out in the DDP and the IIA. Below, we set out some of the most important problems with the SEM Committee's appraisal of energy market Options.

5.1. The "Qualitative Appraisal"

65. Chapter 5 of the IIA includes a "qualitative appraisal" of the Options, which discusses the Options by reference to each of the SEM Committee's appraisal criteria in turn. Unfortunately, this appraisal is selective and biased, as in practice it applies different criteria to different Options. The definition of the criteria is not rigorous and seems to differ according to circumstances. The appraisal does not treat all four Options equally, but often discusses only the advantages of Option 3, as if it had already been selected, instead of using the discussion to drive the selection. Appendix D provides a more detailed review of this part of the IIA.

66. Overall, the "Qualitative Appraisal" set out in the IIA provides no objective or balanced support for the SEM Committee's draft decision.

5.2. Errors Caused by Poor Definition of the Options

67. Some of the most important aspects of the High Level Design are mentioned in only vague terms. However, they have the potential to affect outcomes significantly, and cannot therefore be ignored in any overall evaluation of different Options.

5.2.1. Unspecified design details

68. Under Option 3, the SEM Committee has decided to adopt a "single imbalance pricing regime".[16] All imbalances within the same imbalance settlement period will be settled at the same price, whether the "Balance Responsible Party" is long (net contract position greater than net physical generation) or short (net contract position less than net physical generation). The DDP does not say how this price will be set, although it mentions that it will reflect "the costs of actions taken by the TSOs", implying that the imbalance price will be taken from the offers and bids accepted in the balancing market. (Criteria (6)-(11) would apply to this aspect of the design.)

69. Within the balancing market, the SEM has decided to employ a "marginal pricing mechanism", under which the price for all "activated balancing energy" will be taken from the offer or bid price of the "last" unit that the TSO uses to provide balancing energy.[17] That corresponds to a decision to apply our criteria (7) and (8). In Options 2 and 4, which contain

[16] DDP, paragraph 6.4.49.

[17] DDP, paragraph 6.4.45.

an ex post pool, the "last" unit is the most expensive one required to meet demand, which can be identified within the pooling algorithm (as under the current regime). In Options 1 and 3, however, the TSO may intervene at any time, so the definition of the "last" unit is unclear or ambiguous. This term may mean the last unit *chronologically*, i.e. the price of the offer or bid accepted by the TSO at the time closest to delivery. On the other hand, it may mean the most highly priced offer (or the lowly priced bid) accepted during the lead up to delivery.

70. Whatever it means, price-setting will exclude TSO balancing actions that are driven, not by overall market conditions or surplus or deficit, but by potential gains from trade (i.e. matching low-priced offers with high-priced bids), or by some local constraint. The list of offers and bids eligible to set the imbalance price (which then determines the value of all other electricity contracts) will be adjusted by a "tagging and flagging" system, applied at the discretion of the TSO.[18] Such processes may not be consistent with the need for transparency in price setting. (Criterion (11))

71. Within Options 2 and 4, the price of imbalances would be derived from the ex post pool, leaving no doubt about which outputs can be included in, and which can be omitted from, the calculation of imbalance prices. Within Options 1 and 3, however, price setting will have a subjective element. Within BETTA (which is similar to Option 1), this subjectivity has limited impact, because imbalance prices are in any case intended to be unpredictable, different for surpluses and deficits, and punitive, in order to discourage imbalances. However, the Balancing Guidelines specify the use of a single balancing price. That approach is now being applied in both BETTA and the I-SEM (Option 3).[19] However, as yet, it is unclear how a single electricity market price can be centrally defined in a transparent manner, without relying on an automated schedule of generation (which is only found in Options 2 and 4).

72. Thus, by leaving the imbalance pricing rule undefined, the DDP and IIA overlook a potential problem with Options 1 and 3 and fail to identify a potential advantage for the other Options.

5.2.2. Appraisal errors due to mis-specification of Options

73. Failure to be specific about real-time arrangements has caused analytical errors in the SEM Committee's appraisal, as illustrated by paragraphs 6.4.23 and 6.4.24 of the DDP.

74. Here, the DDP considers an effect of making the DAM "non-mandatory" and describes a situation where wind (or renewable energy) does not participate in the DAM. It claims that the result will be (a) higher prices and (b) a higher cost initial schedule comprising only thermal generation. Those outcomes rest on the assumption that the restricted supply of generation is set against the same level of demand as before – possibly even a forecast of total demand. However, it is hard to envisage market rules that exclude some generators from the DAM without also adjusting the demand by an equivalent amount, so the outcomes (a) and (b) are unlikely to arise in practice.

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[18] DDP, paragraph 6.4.45.

[19] The decision to move to a single imbalance price was announced in mid-May 2014, by the British electricity and gas regulator, Ofgem. See Ofgem (2014), *Electricity Balancing Significant Code Review - Final Policy Decision*, 15 May 2014.

75. The proposed model – with the DAM being "exclusive" but not "mandatory" – implies that demand enters only through voluntary bids from suppliers, not as a centralised forecast of total demand. Suppliers would not bid for electricity in the DAM, if they expected to pay a higher price than in intra-day markets. Due to the potential for arbitrage between day-ahead and intra-day markets, the reduction in day-ahead offers to sell would be matched by a reduction in day-ahead bids to buy. Prices in the DAM would remain comparable with expected prices in the intra-day market – and with the expected price of imbalances, which ultimately determines the value of all contracts signed in advance of delivery.

76. One effect of this arbitrage would be to split trading volumes between the DAM and other markets, thereby reducing liquidity in all of them. Neither the DDP nor the IIA note the likelihood of this outcome. Instead, they take for granted the liquidity of the DAM under Option 3, an assumption based apparently on an earlier design, in which participation in the DAM was mandatory. The SEM Committee is therefore basing its appraisal of Option 3 on an out-dated specification.

77. The fears expressed in the DDP about the effect of making the DAM non-mandatory and excluding wind farms from the DAM therefore indicate either a misunderstanding of electricity markets, or some hidden assumptions about electricity market design that would not withstand scrutiny. The SEM Committee appears to have overlooked the implications of this analysis for market liquidity. Its appraisal of Option 3 appears to be based on an out-dated version, which would perform differently from the latest version in terms of promoting liquidity. Since promoting liquidity is one of the supposed advantages of Option 3, the SEM Committee's decision, which relies on this feature of Option 3, must be regarded as unsound.

5.2.3. Summary

78. These observations indicate gaps in the definition of the chosen Option and its potential effects that might have altered the SEM Committee's appraisal of the Options, judging by our practical design criteria (Criteria (1), (2), (6) and (11), at least). The SEM Committee would need to carry out more analysis to ensure that the chosen Option meets the criteria of efficient market design (particularly by Criteria (6)-(9)). Lacking that analysis, the SEM Committee conducted a selective and prejudiced appraisal of the Options and has reached a decision that is unreliable.

5.3. Inefficiency and Scheduling Risk Due to Euphemia

79. The SEM Committee assumes that market participants will find a way to achieve the desired – i.e. efficient – pattern of output from their generators, even though the primary route to despatch will be a trading algorithm (Euphemia) rather than a despatch programme. This assumption lies behind the SEM Committee's positive appraisal of Option 3 and its focus on the DAM. However, it is not a foregone conclusion that market participants will achieve an efficient pattern of output and demand through their use of Euphemia in the DAM or other markets. Assuming an efficient outcome is not a sound basis for the SEM Committee's decision, as we explain below.

5.3.1. Trading algorithms versus despatch programmes

80. Unlike a despatch programme, Euphemia does not accept offers and bids in a structure that accurately reflects the costs and technical characteristics of individual generators. Instead, Euphemia offers market participants several ways to submit data that are intended to reflect generator characteristics in simplified offer formats. Generators have to choose which of these simplified offer formats best reflects their actual characteristics and how to adjust input data for differences between the simplified offer formats and the complex reality. This discretion over the choice of offer format creates a degree of unpredictability for each user of the system. Different market participants may choose to reflect the complex characteristics of their generators in different ways in response to changing assumptions regarding key attributes of the DAM such as the level of wind generation or demand. The actual outcome achieved by each market participant will then depend not only on how they adapt their own offers for any given day, but also on their ability to predict how other market participants will adapt their offers.

81. No final assessment of the Options will be possible if the SEM Committee cannot be sure that generators have the means to achieve predictable levels of output, consistent with economic merit-order despatch. (Criterion (9)) Euphemia has been developed as a means of trading energy in other countries. Testing of Euphemia is required, to confirm the assumption that it provides a suitable basis for despatching generators in Irish conditions.

5.3.2. Alternative means of achieving efficient production

82. Each Option includes some kind of intra-day market and a balancing mechanism, but the high level descriptions do not say how the TSO will interact with market participants.[20] Market participants wish to operate their generators at least cost, but their plans may conflict with the TSO's need for a feasible and secure pattern of flows over the transmission system. The TSO needs to know when to make balancing trades to rectify problems. To intervene efficiently, the TSO needs to possess a definitive plan for each market participant's generation and consumption.

- If the TSO intervenes too early, before market participants have finalised their plans, they may simply re-create a problem by engaging in another intra-day trade, which will require another round of intervention by the TSO.
- If the TSO intervenes too late, it may only be able to select from a restricted set of expensive, flexible sources of upwards or downwards ramping.

83. These aspects of the market design have the potential to cause inefficient outcomes. This potential differs between the Options, but the DDP and IIA do not take it into account.

[20] In the DDP, paragraph 6.4.57 notes that it will be necessary to decide how day-ahead nominations should be linked to contractual positions, if at all, but it provides no answer to this question.

5.3.3. Summary

84. The use of Euphemia in the day-ahead market is not guaranteed to produce an efficient pattern of output. Intra-day and real-time institutions may correct any forecasting or trading errors, but only if well designed. Unless these institutions are well defined and understood, the market has the potential to produce inefficient outcomes.

85. Including a proper assessment of this potential inefficiency might overturn the SEM Committee's appraisal of the Options and change its decision about the High Level Design. In the absence of any such assessment, the SEM Committee's conclusions are not soundly based.

5.4. Confusion Over Contract Types and Despatch Rules

86. Paragraphs 6.4.3-6.4.5 of the DDP discuss the choice between "physical" and "financial" contracts, with the SEM Committee ultimately proposing "that all forward contracts will be financial in nature, i.e. Contracts for Differences (CfDs)." The reasoning behind this proposal has two parts:

- "Financial contracts can achieve everything that can be achieved by physical forward contracts in terms of hedging short term spot prices…" (para 6.4.3); and
- "…physical forward contracting could aggravate rather than mitigate liquidity concerns by reducing the volumes of trades in the short term markets that are used to reference financial contracts" (para 6.4.4).

87. These reasons only refer to limited aspects of contracting, namely the hedging of "short term spot prices". Respondents may in fact be using the difference between physical and financial contracts to highlight other aspects of risk management, which the SEM Committee has ignored, and which we explore below.

5.4.1. Real time price risk

88. The DDP envisages the day-ahead market as the source of the reference price for a variety of financial contracts ("Contracts for Differences" or CfDs). However, generators also need some way to hedge price risk for variations in output arising after the day-ahead stage, in the intra-day markets, balancing mechanism and settlement of imbalances.

89. The multiplicity of prices after the day-ahead stage will present a challenge for contract designers trying to develop CfDs for hedging these risks. Leaving aside special operations required by the system, Nord Pool settles all real-time volume adjustments in the same hour and zone at the same market price, whether they derive from a balancing instruction issued by the TSO, or from an imbalance attributable to a market participant. Under that approach, a large number of market participants face similar price risks, so those with surpluses can offer CfDs at a predetermined strike price to those with deficits. That solution will not be feasible in the SEM Committee's chosen option, where intra-day markets, balancing trades and imbalances all attract different prices.

90. To offer all market participants a common basis for hedging short term prices would require a unified real-time or *ex post* market operating after the day-ahead market (as in Nord Pool).

The DDP does not consider any such model, or attribute any benefit to models that might be able to operate this way.

5.4.2. Real time volume and scheduling risk

91. If contracts refer to the price in the DAM, generators who cannot predict their actual output at the day-ahead stage will be exposed to variation in the value of the difference between day-ahead sales and actual output ("volume risk"). Generators using renewable energy sources are particularly exposed to this risk but it will affect others who find it difficult to achieve a particular level of sales in Euphemia ("scheduling risk").

92. Euphemia will be used in the DAM to determine each generator's sales and the reference price that determines payments under CfDs. If a generator cannot match its sales in the DAM to the volume of its CfDs settled by reference to the DAM price, it will be exposed to price risk on the difference. Generators will not be able to reduce this exposure by trading in intra-day markets, as shown in Box 1 on page 22**Box 1**. The resulting increase in financial risk may raise the costs of generation borne by consumers through the wholesale electricity market.

5.4.3. Implications for market design

93. Some market participants expressed a desire for physical contracts, which are not permitted in Option 3. The SEM Committee has stated a clear preference for financial contracts over physical contracts. However, it is not clear that the SEM Committee has understood or addressed the concerns of market participants. It appears that market participants may have recommended physical contracts, not as a contract form per se, but as a means of managing scheduling risk within the general process of scheduling and despatch.

94. In wholesale electricity markets, so-called "physical" contracts do not in fact dictate how much the seller must generate or how much the buyer must consume. A physical contract merely requires the parties to notify the contract volume to market, which offsets it against their obligations within that market. For example, under BETTA in Great Britain, contracts are offset against the obligation to pay for *ex post* imbalances. The incentive to generate then comes from the desire to avoid being charged for an imbalance at a price above the cost of one's own generation.

95. In these markets, the process of notifying contract volumes is associated with a right to schedule the output of one's own generators ("self-scheduling").[21] This right avoids exposing market participants to the "scheduling risk" inherent in unpredictable despatch programmes. The need to manage this scheduling risk seems to lie behind the desire of market participants to use physical contracts, not the form of the contract per se.

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[21] Under BETTA, market participants notify their contract volumes separately from their expected generation ("physical notification"). If there is any difference between the two at the final stage, the latter provides a pre-notification of the intention to run an imbalance, for the benefit of the TSO and its operations. In general, market participants try to match their final contract notifications against their expected generation and consumption.

Box 1: Effect of Day-Ahead Imbalances Against CfDs

1. Suppose a generator sells 100 MWh of financial CfDs with a strike price of €50/MWh (equal to its SRMC) and with the DAM price as a reference price. The table below shows the cash flows for a fully hedged generator in a particular half-hour J, when the DAM price is €75/MWh, the CfD is called, the generator produces 100 MWh and it sells 100 MWh in the DAM. The generator's cost of generation is €5,000, its revenue from the DAM is €7,500 and its net rebate to the buyer is €2,500. The generator's net cash flows are €0, meaning *it is perfectly hedged*.

Source of	Prices		Volumes		Cash Flows		
Cash Flow	Cost	Revenue	Cost	Revenue	Cost	Revenue	Net
Units:	€/MWh	€/MWh	MWh	MWh	€	€	€
Generation	50.00		100		5,000		-5,000
DAM		75.00		100	0	7,500	7,500
CFD	75.00	50.00	100	100	7,500	5,000	-2,500
Total					12,500	12,500	0

2. Suppose however that the scheduling risk in Euphemia causes the generator to sell only 60 MWh in the DAM for half-hour J. The generator has shortfall against its CfD volume of 100 MWh, leaving it exposed to the difference between the strike price and the DAM price for 40 MWh. To close this gap, the generator might try to sell another 40 MWh in the intra-day market, *but that will not provide a perfect hedge.*

3. The table below shows the result if the intra-day price falls back to €55/MWh, giving a revenue on sales of 40 MWh (€2,200) that is insufficient to cover the cost of fulfilling the exposed part of the CfD (€3,000=€7,500×40/100). The generator ends up €800 short.

Source of	Prices		Volumes		Cash Flows		
Cash Flow	Cost	Revenue	Cost	Revenue	Cost	Revenue	Net
Units:	€/MWh	€/MWh	MWh	MWh	€	€	€
Generation	50.00		100		5,000		-5,000
DAM		75.00		60	0	4,500	4,500
Intra-Day		55.00		40	0	2,200	2,200
CFD	75.00	50.00	100	100	7,500	5,000	-2,500
Total					12,500	11,700	-800

4. For a generator, therefore, the scheduling risk in Euphemia translates into *either* a volume risk (if day-ahead sales differ from CfD volumes and the generator takes no further action) *or* a price risk (if day-ahead sales differ from CfD volumes and the generator tries to bridge the cap with trades in intra-day markets).

96. The SEM Committee's consideration of different contract types only looks at price risk and says that financial contracts (CfDs) can hedge short term spot prices just as well as physical contracts. However, market participants gain no benefit from hedging short term spot prices, if they cannot be sure that the volume they generate or consume matches the volume in their hedging contracts ("scheduling risk").

97. The DDP and IIA suggest at various points that allowing self-scheduling and physical contracts, or allowing Physical Transmission Rights on interconnectors, would reduce liquidity in the DAM. That seems to be based on a hidden assumption (and possibly a misunderstanding) about the way in which such arrangements would be reconciled with the DAM. The DDP states that the DAM will offer an "exclusive" method of establishing contract or physical nominations day-ahead (although that is not quite clear yet – see DDP, paragraph 6.4.57). If so, holders of physical contracts or transmission rights would probably offer their contracted capacity into the DAM. They would have the same incentives as the owners of generation capacity to enter them into the DAM as capacity for sale and the incentive might be reinforced by obligations. Indeed, the DDP notes in paragraph 6.4.5 that "the Iberian and Italian markets currently require all forward contracts to be nominated into the DA power exchange". If the RAs imposed similar obligations on the I-SEM, PTRs on interconnectors would appear in the DAM. Having physical contracts would then contribute towards liquidity (i.e. volumes) on the DAM, rather than diminishing it.

5.4.4. Summary

98. In the DDP, the SEM Committee does not address the problem of volume/scheduling risk, except by expressing a hope that generators will learn how to achieve their aims through Euphemia (DDP, paragraphs 6.4.30-6.4.36). The existence of such risks would raise the costs of generation and increase prices to consumers. A full assessment of the options would therefore have considered this problem in detail, taking into account a detailed description of the arrangements for scheduling and despatch. This detailed description is missing from both the DDP and the IIA.

99. Exposure to volume and scheduling risks will affect investment incentives. Generators may be able to develop CfDs that provide an *ex post* hedge against imbalance prices, but doing so would split liquidity between the day-ahead and other markets, which would undermine many of the claims in the DDP about the benefits of Option 3. In contrast, any market model with a single real-time or *ex po*st market (as well as a day-ahead market) might offer market participants the opportunity to manage such risks, but the DDP does not recognise this possibility. Discussion of the day-ahead market, reference prices and contracting should therefore consider explicitly all the real-time risks facing generators and how they might manage them. (Criteria (2), (3) and especially (4), but also (9)). Currently, the DDP and IIA lack any discussion of these risks.

100. The DDP and IIA are missing any description of important parts of the alternative trading and despatch arrangements, and fail to consider the associated risks to market participants. The appraisal of the proposed Options is therefore incomplete and necessarily subjective.

5.5. Mis-Specification of Interconnector Impacts

101. The treatment of interconnectors forms a major part of the evaluation of Options for the I-SEM. That is understandable, given that the current reform proposals are intended to promote more efficient cross-border flows within the EU's internal electricity market. However, the SEM Committee has not properly specified the output variables that are relevant for its appraisal, leading to a decision that is based on an incorrect definition of efficiency and an incomplete specification of the market model itself, as explained below.

5.5.1. Incorrect definition of efficiency

102. The DDP discusses the treatment of interconnectors in paragraphs 6.4.7-6.4.20. Section 5.4 of the IIA contains detailed modelling of the Irish and British markets and the effect of using interconnectors inefficiently. This modelling shows that inefficient arbitrage between markets leaves potential gains from trade unused, but this finding is a foregone conclusion. The modelling itself does not provide any basis on which to distinguish between the Options.

103. Efficiency depends on the actual outcome of despatch and cross-border *flows*, not on the cross-border *trades* achieved in any particular market. The analysis set out in the IIA actually indicates the importance of achieving efficient cross-border flows in real time (given the day-ahead outcome). However, the DDP and IIA give little attention to real-time output and demand. Instead, the IIA distinguishes between Options by reference to their impact on the efficiency and liquidity of day-ahead trading.[22]

104. In practice, the efficiency of day-ahead trading may be unimportant for actual outcomes. Collaboration between TSOs could ensure efficient *use* of interconnectors in real time under any Option, by re-arranging cross-border flows in response to Balancing Market offers and bids. ACER’s Balancing Guidelines oblige TSOs to collaborate to increase efficiency (see section 3.1), but the DDP and IIA never consider the nature of that collaboration or its effect on outcomes.

105. Indeed, the IIA never explains what the authors are assuming under each Option about UIOSI conditions on PTRs, on the potential for adjusting cross-border flows in the ID markets or on the role of the TSOs and the potential for optimisation of cross-border through inter-TSO balancing trades. Any of these mechanisms would affect the efficiency of actual outcome, regardless of the trading position achieved in advance in the DAM.

106. Having focused only on the efficiency of arbitrage, rather than efficiency of use, the IIA then assumes that cross-border linking of DAMs in Option 3 will achieve more efficient arbitrage than any other Options, or than “physical transmission rights” (PTRs).[23] However, these claims are mere assertions based on unstated assumptions about traders’ behaviour under each Option. They are not backed up by analysis or evidence. Some of the claims seem to be based on contradictions or misconceptions.

107. For example, paragraph 5.4.39 of the IIA states that Option 2 faces a problem, because it will split liquidity between “the European DAM and the ex-post pool”. However, a non-mandatory version of Option 3 offers a “European DAM” and a single price for *ex post* imbalances,[24] as well as intra-day markets, which offers the same potential for splitting liquidity. Yet the evaluation of Option 3 in paragraphs 5.4.40-41 makes no mention of this

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22 IIA, paragraphs 5.4.38-43.

23 IIA, paragraphs 5.4.40-41.

24 The SEM Committee proposes to use the balancing market to identify a single price for imbalances based on marginal cost, just as a gross pool would. “The SEM Committee proposed decision is that the balancing market will employ a marginal pricing mechanism. This means that the last unit used to provide balancing energy will set the price for all activated balancing energy. Marginal pricing is in line with the thrust of the EU target model for balancing.” DDP, paragraph 6.4.44.

potential tendency to split liquidity, observing instead that “High levels of participation in the DAM and IDM by variable renewable generation will better deliver optimal use of the interconnectors”. We can see no reason for this favourable view of Option 3, given the problems that the SEM Committee has ascribed to Option 2.

108. Similar problems arise in the discussion of interconnectors. Appendix C sets out statements about FTRs and PTRs made in section 6.4 of the DDP and explains why they are incorrect or misleading.

5.5.2. Confusion over efficiency of different interconnector contracts

109. The DDP frequently states that offering physical transmission rights on the interconnectors will limit liquidity or efficiency.[25] However, it is not clear why this statement is necessarily true. The “exclusive” nature of the DAM process means that holders of physical interconnector capacity would have the same incentives to pass their sales through the DAM as the owners of any generator capacity. Interconnector capacity covered by PTRs would therefore offer as much liquidity to the DAM as generation capacity.

110. Moreover, normal despatch procedures – sometimes formalised as “use-it-or-sell-it” (UIOSI) or “use-it-or-lose-it” (UIOLI) rules – can make unused interconnector capacity available to other traders or to the TSOs on either side of the interconnector. As a result, traders with PTRs would not be able to withhold interconnector capacity,[26] and there is plenty of scope for intra-day adjustments to achieve efficient cross-border flows, no matter how efficiently or inefficiently arbitrage works at the day-ahead stage. If the UIOSI rule applied before the DAM closed, interconnector capacity would be available to the DAM on the same basis as under an implicit auction.

111. Indeed, many electricity markets have found it advisable to adopt PTRs, to make it possible for generators in neighbouring markets to offer reliable capacity. (See section C.3.3 in Appendix C.). The SEM Committee has not considered this possibility and so is forced to rule out cross-border trade in capacity (in favour of a compromise position on interconnector capacity). Allowing PTRs on interconnector capacity would therefore have a positive effect on security of supply, competition and liquidity (in energy and capacity markets), which the IIA does not take into account.

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25 See DDP, paragraphs 6.3.14, 6.4.11-18. “One market participant believes that FTRs should result in the same practical outcome as PTRs with use it or sell it (UIOSI) requirements but that the benefit of FTRs is that physical capacity of the interconnector in the forward market is not used up, that that capacity is therefore available in the day ahead (DAM) and intraday markets and that this will assist liquidity in these timeframes. Concern is expressed that PTRs would mean taking interconnector capacity out of the market and reducing liquidity.” (DDP, para 6.3.14) “Furthermore, in order for the all island market to integrate further into the European Internal Market it is important that the existing interconnectors are used optimally. This will not only ensure that consumers in Ireland and Northern Ireland who have funded these assets receive adequate return on their investment but also that efficient signals are sent for future cross border investment, through competitive energy market prices on both ends of the interconnector. The SEM Committee believes that FTRs best achieve these objectives.” (DDP, para 6.4.17)

26 At least, the incentive to withhold interconnector capacity will be no different from the incentive to withhold any other form of capacity. If such withholding is likely, the proposal faces a major problem not addressed in the DDP, which is not specific to interconnector capacity. In fact, withholding interconnector capacity is very difficult, if despatch procedures allow the TSO to make unused interconnector capacity available to others. However, the DDP has not set out detailed despatch procedures that would make this point clear.

112. It cannot therefore be argued that interconnector capacity covered by PTRs would somehow diminish liquidity. The statements about PTRs set out in the DDP are misinformed or misleading to readers.

5.5.3. Summary

113. Errors in the discussion of cross-border flows, and a failure to consider fully the alternative contract forms, effectively render invalid the conclusions reached in the DDP about the use of interconnectors.

5.6. Treatment of Liquidity, the DAM and Forward Markets

114. The DDP acknowledges on page 7 that measures will be needed to promote forward markets; this observation applies to all Options. However, the SEM Committee's appraisal of the Options is prejudiced by a biased treatment of this point, in favour of Option 3.

5.6.1. Selective use of the benefit of the doubt over liquidity

115. Paragraph 5.5.5 of the Impact Assessment accepts that Option 3 would need unspecified additional measures to promote liquidity in forward markets. Judging by experience in Britain, allowing for such additional measures would be particularly important for the appraisal of Option 1. However, the Impact Assessment does not consider whether additional measures would allow the other Options to perform as well as, or better than, Option 3 in this respect *or in any others* (e.g. in day-ahead liquidity, for example).

5.6.2. Failure to consider the proper role of forward markets

116. It is not the purpose of an electricity sector to create forward markets for their own sake. Forward markets have not proven necessary (in Britain, for example) to promote efficient investment in new generation capacity (which lasts much longer than any forward curve). However, forward contracts provide the basis for independent retail suppliers to set tariffs for the coming year or two. Without forward contracts extending at least one or two years into the future, independent retail suppliers would be unable to make such offers to customers and would lose out. In the context of the I-SEM, this situation would violate Criterion (13), since it would allow the dominant player in the generation market to extend its influence in the retail market, by withholding forward contracts and disadvantaging independent retail suppliers.

5.6.3. Summary

117. The robustness of the forward curve is a significant feature of any future electricity market intended to replace the SEM. However, in the appraisals set out in the DDP and IIA, the SEM Committee has allowed Option 3 to benefit from unspecified additional measures to promote forward markets, whilst not assessing whether these or other unspecified additional measures would be advantageous under Options 1, 2 and 4.

118. The assessment therefore fails to compare the Options on a level playing field. As a result, the conclusions reached in the DDP must be considered unsound.

5.7. Conclusion

119. The "Qualitative Appraisal" set out in the IIA provides no objective or balanced support for the SEM Committee's draft decision.

120. There are gaps in the definition of the chosen Option and its potential effects that are significant enough to have affected the SEM Committee's appraisals. More analysis would be required to ensure that the chosen Option meets practical and objective criteria of efficient market design. In the meantime, the SEM Committee's appraisal is selective and prejudiced, rendering its decision unreliable.

121. Euphemia is not guaranteed to produce an efficient pattern of output in the day-ahead market, but the SEM Committee assumes that it will. In fact, given the lack of detail on intra-day and real-time institutions, any of the proposed High Level Designs has the potential to produce inefficient outcomes. Without a proper assessment of this potential inefficiency, the SEM Committee has no sound analytical or evidential basis for its decision.

122. The SEM Committee has not addressed the problem of volume/scheduling risk. A full assessment of the options would have considered this problem in detail, taking into account a detailed description of the arrangements for scheduling and despatch. The DDP and IIA are missing any description of these arrangements and fail to consider the associated risks to market participants. The appraisal of the proposed Options is therefore incomplete and necessarily subjective.

123. Errors in the discussion of cross-border flows, and a failure to consider fully the alternative contract forms, effectively render invalid the conclusions reached in the DDP about the use of interconnectors.

124. In relation to the liquidity of forward markets, the assessment fails to compare the Options on a level playing field. As a result, the conclusions reached in the DDP must be considered unsound.

125. We conclude:

- that the SEM Committee's description of the Options is incomplete and in some cases erroneous;
- that SEM Committee's appraisal of the Options is selective, subjective and prejudiced; and
- that the SEM Committee's draft decision is not soundly based on evidence or analysis.

6. Capacity Remuneration Mechanism

126. In its Draft Decision Paper, the SEM Committee concludes that a "Reliability Option" (RO) is the Capacity Remuneration Mechanism (CRM) best suited to meeting the needs of the I-SEM. However, this conclusion is not soundly based because:

- the SEM Committee's description of ROs, and hence its evaluation of them, is *incomplete*;
- the SEM Committee's appraisal applies criteria in a *selective* manner; and
- the SEM Committee has evaluated CRMs against criteria that vary in scope and in definition, introducing a *bias* into the appraisal.

127. Because of these flaws in the appraisal of the various CRMs, the SEM Committee's choice is not soundly based.

128. In the following sections, we illustrate these points by reference to the arguments in the DDP and IIA. The comments below should be read alongside our two previous contributions on the topic: (1) a report on the choice of CRM,[27] submitted by Viridian in April 2014 in response to the RAs' Consultation Paper of 5 February 2014; and (2) a memo,[28] written at the request of the RAs, with more detail on Reliability Options and their role in solving the "missing money" problem.

6.1. Mis-Match Between Problems and Proposed Solutions

129. In chapter 7 of the DDP, the SEM Committee concludes that there is a need for a CRM in the I-SEM because:

- the risk of intervention to keep wholesale prices down deters efficient investment;
- reliability is a public good;
- there is inadequate DSR and insufficient long-term hedging, and
- large, indivisible investments may cause electricity prices in Ireland's relatively small market to follow a "sawtooth" pattern (which the SEM Committee views as a problem for plant that is exiting the market and for new entrants[29]).

130. In practice, a CRM will only address problem (1) if it removes the incentive for intervention, and will only address problems (2)-(4) if it changes incentives for investment in physical capacity. The SEM Committee appears to assume that Reliability Options (as specified in the DDP) will address these problems, but this assumption applies only in very specific

[27] G. Shuttleworth, G. Anstey and M. Mair (2014), *The Capacity Remuneration Mechanism in the SEM*, Prepared for Viridian, 4 April 2014.

[28] G. Shuttleworth and G. Anstey (2014), *Reliability Options: Clarification Note*, 2 May 2014

[29] SEM Committee (2014), *Integrated Single Electricity Market (I-SEM) High Level Design for Ireland and Northern Ireland from 2016 - Draft Decision Paper*, SEM-14-045, 9 June 2014, Draft Decision page 58-59, para 7.2.5: "Notably, the indivisibility issue is an issue for exit as well as entry."

conditions that are not set out in the DDP or the IIA. The SEM Committee will compile a more detailed design in the next phase, but no proper evaluation of the various CRMs is possible at this stage without considering at least some of these detailed design features. If the SEM Committee had considered these detailed design features, it might have reached a different decision.

6.1.1. Removing incentives for intervention

131. First, the SEM Committee has not explained precisely how ROs will remove the incentive for political or regulatory intervention in electricity markets, and hence reduce the risk of such events occurring.

132. Adding ROs to the electricity market will only reduce or remove the risk of political or regulatory intervention in electricity markets in specific circumstances. For instance, ROs would reduce the political pressure on regulators to intervene in the following circumstances:

(1) Wholesale electricity prices feed directly through into the bills of retail customers;

(2) High wholesale electricity prices above a certain threshold (e.g. €1,000/MWh) raise the bills of retail customers above the level that is politically acceptable and provoke some kind of regulatory/political intervention to cap prices;

(3) Reliability Options (as specified in the DDP) offer a rebate to consumers when wholesale prices rise above the threshold;

(4) The rebate offsets the rise in consumer bills and prevents consumer bills from rising above the level that is politically acceptable;

(5) ROs therefore remove the incentive for regulatory/political intervention.

133. If this chain of argument lies behind the SEM Committee's conclusions, those conclusions are unsound, because several steps in this chain of argument may not be true in the I-SEM.

134. For instance, point (1) is most obviously true in a market where retail tariffs are regulated and are tied directly to wholesale electricity prices, but it may not apply in a market like the I-SEM, where retail tariffs are set competitively. In competitive conditions, unexpected rises in wholesale electricity prices, such as those that occur when capacity is short, do not feed through immediately into retail consumer bills.[30]

135. Furthermore, point (4) would only be true if there were a *direct* link between wholesale electricity prices and retail tariffs, *and* if the rebates paid under the ROs were passed on to retail consumers in direct proportion to their exposure to wholesale electricity prices. Under these conditions, high wholesale electricity prices lead to an increase in retail tariffs that is offset exactly by the rebate. Both these conditions might hold in a system of regulated retail

[30] We are assuming here that suppliers fix their tariffs for a certain period and can only adjust them prospectively. Unexpected price rises come and go before they can adjust tariffs. Expected price rises (due to an anticipated shortage of capacity) would be included in such tariffs, because they change suppliers' view of the likely future costs of supply. However, that effect would be muted and spread out over a long period, because it would reflect the probability of a shortage, rather then the full cost of an actual shortage. Such muted price increases are less likely to prompt political/regulatory interventions.

tariffs. However, these conditions may not hold in the I-SEM, at least not without a major overhaul of retail tariff regulation.

136. Without such detailed regulation of retail tariffs, rebates paid from generators to a central fund, and passed on to retail suppliers, may not benefit all consumers to the correct extent. In fact, they may not benefit consumers directly at all, as competing suppliers may have no incentive to pass on the actual rebates to their customers. Instead, they may include the anticipated level of rebates in a discounted price (just as they include the anticipated level of costs, rather than actual costs). Where suppliers offer their customers a fixed price, passing on any rebates they receive would harm their financial position (because they would be incurring higher costs to purchase energy, but receiving a fixed revenue from customers). Receipt of such rebates would have a perverse effect on their consumers (whose net cost of energy would fall at a time when electricity wholesale prices were rising).

137. The DDP and the IIA do not set out any explanation as to how ROs will reduce the risk of intervention. The analysis above suggests that ROs might not solve this problem, without a major overhaul of the regulation of retail suppliers. The SEM Committee's decision therefore fails to take account of potentially major effects and costs.

6.1.2. Replacing the missing money to encourage investment

138. In order to address the missing money problem, ROs would have to provide revenue in addition to that offered by the (imperfect) energy price. However, Reliability Options as specified in the DDP offer no particular advantage to investors and provide no additional incentive for investment over the wholesale market prices and contracts that would be available anyway.

139. We discussed this point in the memo dated 2 May 2014 and entitled "Reliability Options: Clarification Note", which Viridian duly forwarded to the RAs. In that memo, we explained that ROs would only offer additional revenue above the energy price if it was backed up by additional penalties for failing to provide capacity, as in the design currently being adopted in Great Britain (and in other countries' schemes as well).

140. In reply, to support its particular version of Reliability Options, the SEM Committee quoted two academic papers in the DDP, Vazquez et al (2003) and Cramton and Stoft (2008).[31] In practice, none of these authors support the position of the SEM Committee. On the contrary, these authors (and others) agree either explicitly or implicitly with the need for Reliability Options to be tied to physical capacity, as well as to the energy market, as shown below.

- **Vazquez et al (2003)**

141. Vazquez et al do not state explicitly that a Reliability Option settled by reference to the energy price is sufficient to solve the missing money problem. They note that Reliability Options solve a particular form of the missing money problem, i.e. the threat of regulatory intervention. We discuss above the conditions in which this statement is true and whether

[31] DDP, para 8.4.11, footnote 29.

this effect applies within the I-SEM. However, the description of their proposed design explicitly mentions the need for a physical link to the financial options bought in the auction. The relevant extract reads as follows:

> *"Additionally, a physical delivery obligation is tied to the option, in order to provide stronger incentives for the generators and to make sure that the more reliable production units will be in a better position at the reliability market. This means that an option-selling generator that, when the prices are high, fails to provide the power he committed to produce has to bear an extra penalty for each megawatt non-delivered."*[32]

142. Thus, although Vasquez et al acknowledge the potential benefit of ROs in reducing the temptation to intervene, they explicitly assume that ROs contain terms obliging generators to provide physical capacity, and to bear "an extra penalty" for not doing so, over and above the energy price.

- **Cramton and Stoft (2008), Cramton, Ockenfels, and Stoft (2013)**

143. In their 2008 paper,[33] Cramton and Stoft do not explicitly state that additional penalties are necessary, but they cite several systems where the TSO verifies that capacity is made available and they assume implicitly that generators must deliver capacity (which requires some kind of incentive and penalty system). The closest they come to stating this assumption is in relation to the variation of design required in a hydro-based electricity market:

> "If supply is mainly from hydro-electric generation, the limiting factor is not likely to be capacity (the ability to provide energy in peak hours) but rather, firm energy (the ability to provide energy in dry periods).[fn] As a consequence the TSO will need to purchase firm energy options. **Just as capacity is the physical basis for reliability options**, so firm energy options have a physical basis that involves a longer-term supply of energy."[34]

144. They made this assumption explicit in a more recent working paper, dated 2013.[35] That paper contains a discussion which is worth quoting at length. It explains the need to tie ROs to physical capacity, and the consequences of failing to define the amount of capacity (C_{BID}) that each generator may sell:

> **"d. Setting the capacity rating, CBID**
>
> So far, we have not addressed the question of what determines CBID. It would be desirable for investors to be motivated to bid the quantity of capacity honestly

[32] Vazquez, C., Battlle, C., Rivier, M., and Perez-Arriaga, I., (2003), *Security of Supply in the Dutch Electricity Market: the role of Reliability Options*, page 11.

[33] Peter Cramton and Steven Stoft (2008), *Forward Reliability Markets: Less Risk, Less Market Power, More Efficiency*, published in Utilities Policy, 16, 194-201, 2008 [emphasis added].

[34] Peter Cramton and Steven Stoft (2008), *Forward Reliability Markets: Less Risk, Less Market Power, More Efficiency*, Utilities Policy, 16, 194-201, 2008, page 10. (Page number refers to offprint of article.)

[35] Peter Cramton, Axel Ockenfels, and Steven Stoft, *Capacity Market Fundamentals*, 26 May 2013

because, for old plants and demand-side resources, they will have a more accurate view of its value than does the system operator. Also, investors will lobby to be allowed to determine CBID. However, as long as there is a significant amount of missing money, investors will want to set CBID as high as possible.

[…]

Typically, investors will want the highest possible C_{BID}, but what is the right C_{BID} to assign them? This value should not inappropriately favor one type of generator over another; otherwise the market will select the wrong mix of capacity types. So C_{BID} should be set so that the capacity market mimics a perfect energy-only market. This means that every MW of capacity should be paid the same on average as they would be paid by optimal scarcity prices, taking account of the fact that some generators are more reliable than others. If a generator is available twice as often during scarcity events, then it would receive twice as much peak revenue from an energy-only market. So it should also receive twice as much from a capacity market.

So, in order to properly reward capacity for its contribution to adequacy, it is necessary to set C_{BID} to reflect the actual contribution of generating units to adequacy. (In a more complete model, we would find that C_{BID} should reflect a generator's contribution to all scarcity events including those caused by security issues.) This means setting C_{BID} equal to nameplate capacity times the probability that the unit will provide capacity during a scarcity event.

Another reason for the system operator to determine the capacity ratings to be used in the auction is to achieve consistency between the estimate of needed capacity and the amount of capacity purchased. For example, the system operator might find that a reliable market requires the 100 existing generators, with an estimated effective capacity of 30 GW, plus another gigawatt of new capacity. If generators determined their own C_{BID} values, they would likely inflate them and when the auction bought 31 GW of capacity it would find this consisted of 90 of the existing generators and no new ones. At that point, 10 existing generators might retire and the system would become unreliable. Using the same capacity values for determining required capacity and for the purchase of capacity eliminates such discrepancies."[36]

145. Thus, these authors point out that generators and demand-side resources will tend to overstate the amount of reliable capacity they possess, and that the designers must set up (and hence the regulators must approve) a rule for designating a fair amount of capacity to each potential source.

- **C. Batlle, P. Mastropietro, P. Rodilla, I.J. Pérez-Arriaga (2014)**

146. A recent paper by a group of Spanish academics also highlights the need for ROs to be backed up by certification of capacity and penalties for non-delivery of capacity (in addition

[36] Peter Cramton, Axel Ockenfels, and Steven Stoft, *Capacity Market Fundamentals*, 26 May 2013, pages 10-11. (The omitted paragraph contains a technical discussion of problems in the treatment of demand-side resources, which is not relevant here.)

to the cost of making good the supply of energy).[37] The authors include Pablo Rodilla (whom the RAs invited to give a presentation at a recent workshop on the High Level Design) and Ignacio Pérez-Arriaga (until 2012 an Independent Member of the Irish Regulatory Committee for the Single Electricity Market). A short extract illustrates their support for a regulatory penalty in addition to settlement at the energy price:

> "The non-fulfilment of the contract commitments must be penalised by the regulator. The penalty should be high enough to dissuade the selected bidders to manage their generation plants for them not to accomplish their obligation. On the other hand, the penalty should not be excessive in case of prolonged technical unavailability." [38]

147. The authors identify the absence (or ineffectiveness) of such additional penalties in the Colombian system as a potential constraint on achieving a reliable supply of generation.

148. Thus, several authors, including those cited by the SEM Committee in the DDP, explain that ROs should be backed up by a system of capacity certification and penalties for under-performance, over and above the obligation to pay for an alternative supply of energy.

149. In the DDP, however, the SEM Committee refers to such arrangements only briefly, and as if they were an optional extra in ensuring that Reliability Options solve the missing money problem:

> "Pure reliability options do not have additional penalty mechanisms for non-delivery other than the amounts paid back when the RO is called. However, other markets have considered combining reliability options with penalties for physical non delivery. The requirement for these in the I-SEM context is not clear at this stage and this will be an issue to be considered in the detailed design of the mechanism.
>
> The eligibility rules will determine who can issue ROs, for example, whether option issuers will need to have physical plant capacity or a credible generation project, or what criteria demand side participants will be required to meet. The eligibility rules will also consider participation of cross border players and potentially demand providers. The eligibility rules will be determined as part of the detailed design of the mechanism."[39]

150. Despite these caveats, the SEM Committee refers to ROs throughout the DDP as "market-based", implying that they avoid the regulatory decisions required by other CRMs. In practice, as shown above, Reliability Options need arrangements linking them to the delivery of capacity to ensure that ROs solve the missing money problem. The need for such

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37 C. Batlle, P. Mastropietro, P. Rodilla, I.J. Pérez-Arriaga (2014), *The System Adequacy Problem: Lessons Learned From The American Continent*,IIT Working Paper, February 2014 version.

38 C. Batlle, P. Mastropietro, P. Rodilla, I.J. Pérez-Arriaga (2014), *The System Adequacy Problem: Lessons Learned From The American Continent*,IIT Working Paper, February 2014 version, pages 21-23.

39 DDP, paras 8.4.22 and 8.4.23.

regulatory arrangements undermines the SEM Committee's repeated claims that ROs are an entirely "market-based" solution to the missing money problem.[40]

151. The failure to consider these arrangements in this phase means the SEM Committee has not carried out a complete appraisal of the different CRMs (even at a high level). Instead, the SEM Committee's representation of the CRMs is selective, with the key regulatory features of Reliability Options being given little emphasis relative to the regulatory features of other CRMs. This mis-representation of ROs biases the SEM Committee's choice of CRM and leaves the draft decision without any basis for asserting that ROs will address the missing money problem. As a result, the draft decision to select ROs as the preferred form of CRM is unsound.

6.2. Inaccuracies in the Description of CRMs

152. Section 6.1 highlights a significant lack of detail in the SEM Committee's specification of ROs, but the problem extends to the SEM Committee's specification of other CRMs and hence to their evaluation.

153. The DDP maintains the distinction between "price based" and "quantity based" CRMs for the purpose of evaluating different kinds of CRM for the I-SEM. However, the distinction remains an artificial one, as we pointed out in our earlier report. Many of the assertions in the DDP about price based CRMs apply equally to the quantity based CRMs and vice versa, whilst some assertions apply only to extreme cases - which in practice means to none at all.

6.2.1. Definition of different types of CRM

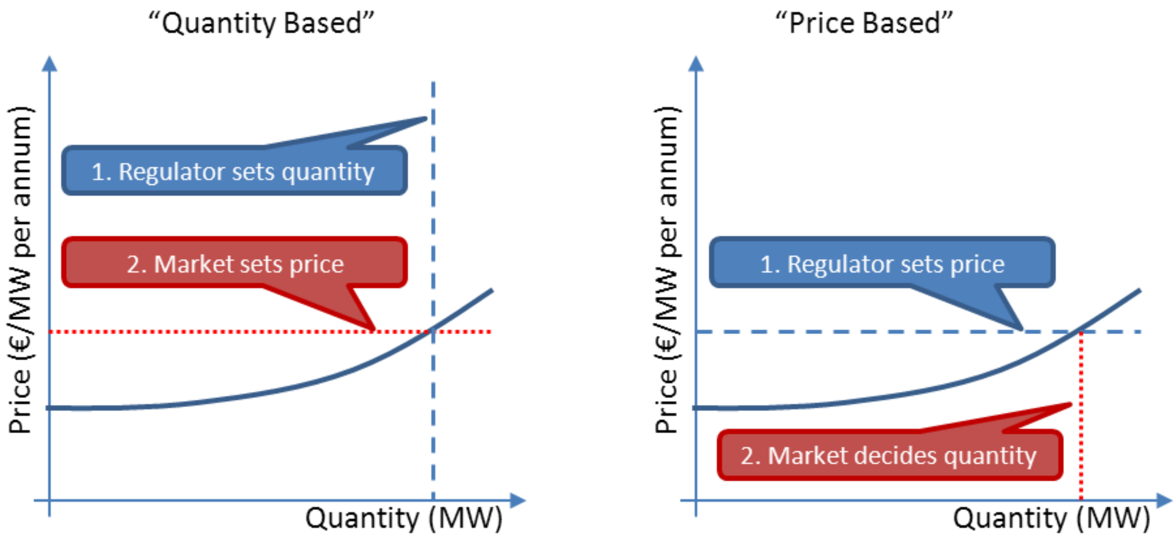
154. The SEM Committee defines a quantity based CRM as one where the regulator specifies the quantity of capacity required for supply adequacy and lets a market or auction define the price of that capacity.[41] Figure 1 shows such a scheme on the left hand side. The upward sloping curve represents the supply of capacity, showing what quantity is supplied at each price. The vertical dashed line represents the demand for capacity, defined by the regulator as a fixed quantity. The horizontal dotted line shows the price the market will set for supplying that quantity.

155. Similarly, the definition of a pure price based CRM would describe schemes where the regulator specifies a price for capacity and lets the market decide what quantity of capacity to offer at that price. The right hand side of Figure 1 shows such a scheme, with the same upward sloping supply curve. The horizontal dashed line represents the demand for capacity, defined by the regulator as a fixed price. The vertical dotted line shows what quantity the market will supply at that price.

40 DDP, para 8.4.12 and passim.

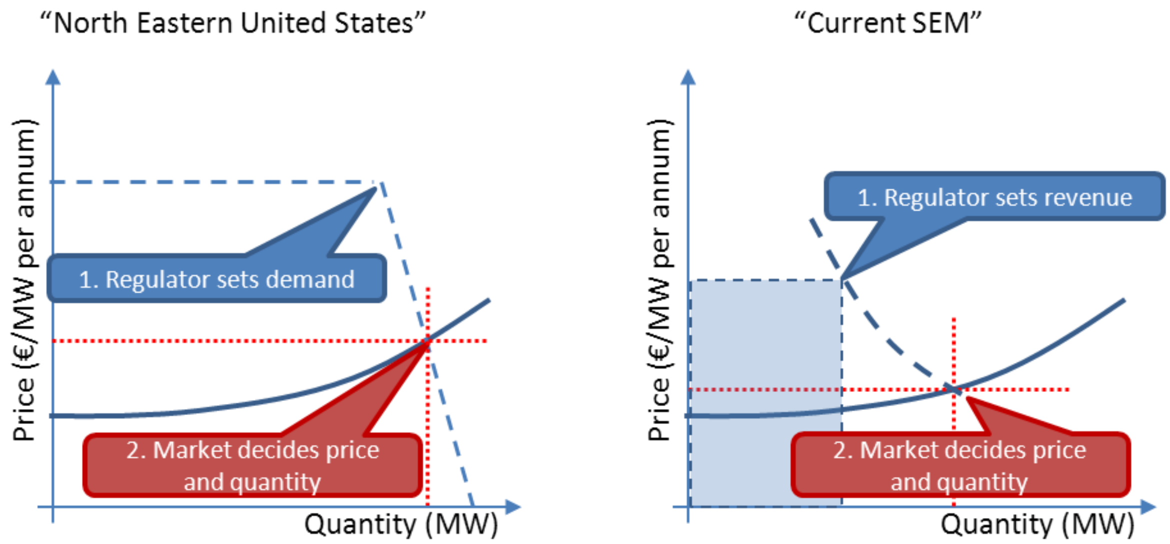
41 DDP, para 8.4.2.

Figure 1: Price and Quantity Based CRMs



156. The schemes in Figure 1 represent extreme cases, where demand for capacity is either a vertical line or a horizontal line. In practice, many CRMs include a sloping demand curve, so that the buyer can call for more capacity if the price is low, and less capacity if the price is high. Figure 2 illustrates how these schemes work.

Figure 2: CRM With A Sloping Demand Curve



157. The left hand side of Figure 2 shows a stylised representation of capacity schemes operating in parts of the north eastern United States, where the regulator sets the parameters of a formal demand curve (the horizontal and sloping dashed lines) and the market chooses a price/quantity combination on that curve by reference to the supply curve.

158. The right hand side of Figure 2 shows a similarly stylised representation of the capacity scheme operating in the SEM at present. Here, the regulatory authorities set a total annual revenue for capacity, defined as a certain quantity multiplied by the annual cost of a new entrant and shown in the diagram as the area of the shaded rectangle. This annual revenue can be divided among different quantities of capacity, as represented by the curved dashed line (in practice, a demand curve with an elasticity of -1). The market then chooses a price/quantity combination on that curve by reference to the supply curve. The diagram in Figure 2 shows higher ("excess") capacity achieving a lower price per MW.

159. The schemes in Figure 2 represent intermediate cases, lying in between the vertical and horizontal demand curves shown in Figure 1. All of these schemes produce a result that adjusts to local conditions, by choosing a combination of price and quantity which reflects the cost and valuation of capacity.

160. Recognising the nature of these intermediate cases shows the incompleteness of the SEM Committee's description and appraisal of CRMs.

6.2.2. A brief note on "double payment"

161. When considering the introduction of a CRM, the designers sometimes ask whether it will lead to "double payment" of generators, i.e. if capacity will be remunerated twice over for the high value of electricity during peak periods – once in the energy market and once in the capacity market. In cases where the need for a CRM is based on the recognition of a "missing money" problem, however, such considerations no longer apply. The explicit purpose of a CRM is to provide a source of additional revenue, over and above the amount (whatever it is) that the energy market is expected to provide. In other words, if the CRM pays money which would otherwise be "missing", the question of double payment no longer applies.

6.2.3. Errors in the appraisal of CRMs

162. The DDP mentions only price based and quantity based CRMs. However, in the intermediate schemes in Figure 2, the regulator sets out different combinations of prices and quantities, as represented by the whole demand curve, whilst the market chooses to settle at one of those combinations of price and quantity.

163. The SEM Committee describes various schemes that employ a demand curve as "price based" and categorises its proposed Reliability Option scheme (CfDs bought through centralised auctions) as "quantity based".[42] In practice, centralised auction schemes (such as those in the north eastern United States) and payment mechanisms (such as the existing CRM in the SEM) both use demand curves to specify the different quantities of capacity that will be procured at different price levels. In the New England market, which operates ROs similar to the SEM Committee's proposed design, the market operator (ISO-NE) employs a demand curve with a fixed volume of capacity for some price levels, plus a price cap and a price floor

42 "A price based capacity market employs a demand curve, i.e., a price that all suppliers will be paid based on an aggregate amount of eligible capacity." DDP, para 8.4.3.

(i.e. prices at which the level of capacity procured in the auction may vary). ISO-NE has recently filed a sloped demand curve for consideration by the Federal Energy Regulatory Commission (FERC) such that the volume of capacity procured by auction will vary with every change in the price between the cap and floor.[43]

164. The DDP not only describes all these intermediate cases as "price based", but also discusses them as if they were purely price based, with no adjustment to demand when prices rise above, or fall below, a certain level. That categorisation of these schemes is inaccurate.

165. Moreover, in many places, the SEM Committee makes statements about price based CRMs that would only be true for the price based scheme shown in Figure 1, where the regulator sets a fixed price. Many of these statements would not be true for CRMs classified by the SEM Committee as "price based" but where in fact the price and quantity can both vary along a sloping demand curve as in Figure 2. For instance, the SEM Committee argues that in "the price based scheme in the current SEM the value of capacity is largely based on a desktop study into the value of new capacity without a competitive market test".[44] However, the current scheme is an intermediate scheme, in which the calculation sets a total revenue and a demand curve determines the trade-off between the price of and quantity of capacity. Competition for the opportunity to supply capacity determines the price of capacity in such schemes, whether the price derives (directly or indirectly) from a regulatory calculation, as in the current SEM, or is set by centralised auction, as in the proposed RO.

166. The SEM Committee also states that, in a quantity based scheme, "the market determines the price and technology of capacity and the regulator determines the one thing that the market has no information on, that is the level of capacity adequacy that is socially optimal".[45] This argument ignores the information problems facing both sides. The market may have better information about the technology and its costs and be unable to decide the optimal level of capacity, but the regulator has to determine the optimal level of capacity with limited information about the cost of capacity for each technology. In the case of intermediate schemes of the kind that markets actually implement, the regulator does not determine "the" optimal level of capacity, but rather a demand curve of different optimal capacities at different prices. Essentially, it sets out the regulator's view of the marginal benefit of capacity to society at every level of security, so that – whatever the cost turns out to be – the market procures an amount of capacity that is close to the efficient level.

167. The SEM Committee's evaluation of CRMs of the type shown in Figure 2 is therefore influenced – and biased – by emphasising the inflexibility and potential problems associated with the purely price based scheme shown in Figure 1. Many of these statements would not apply to intermediate (price/quantity) schemes, including the SEM's current CRM.

168. The SEM Committee has therefore mischaracterised many CRMs and/or criticised price based schemes for possessing fixed price characteristics that do not exist in reality. This error

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[43] *Motion To Intevene And Protest Of The New England Power Generators Association, Inc. And Electric Power Supply Association before the Federal Energy Regulatory Commission*, 1 April 2014.

[44] DDP, para 8.4.6.

[45] DDP, para 8.4.6.

has biased the SEM Committee's evaluation of CRMs and distorted its final choice. The draft decision is not therefore soundly based.

6.3. Faulty Reasoning Behind the SEM Committee's Decision

169. The SEM Committee concludes in favour of ROs for a number of reasons based on application of the high-level principles used in the Initial Impact Assessment. However, the CRMs are not sufficiently well-specified to allow a proper evaluation and the criteria have been applied in a selective and biased manner. As a result, the evidence provided in the IIA does not provide a sound basis for the SEM Committee's draft decision.

170. Below, we discuss key sections in the appraisal, relating in particular to the reasons given for choosing a "quantity based scheme" over a "price based scheme", and how the text betrays a lack of understanding or subjective and ill-informed choices.

- **Reason 1: "A quantity based scheme will provide a more competitive market based solution for the valuation of capacity than a price based scheme".[46]**

171. As explained above, the distinction between quantity based and price based schemes is blurred by the adoption of sloping demand curves, so that neither is more "market based" than the other. Higher prices for capacity lead to a lower quantity being demanded, and vice versa. Even schemes in which the regulator nominally fixes a quantity or a price will face pressure for similar adjustments, albeit on an *ad hoc* basis rather than through a formula. As a result, there is less difference between the outcomes generated by each scheme that the DDP implies.

172. Moreover, the DDP applies appraisal criteria without defining complex terms such as "more competitive". The comment above seems to apply to competitiveness in the *process* of allocating capacity revenues, rather than to the competitiveness of the supply-side structure of the market (which is broadly unaffected by the choice of scheme). If so, this statement fails to recognise the different ways in which competition takes place. In quantity based schemes, generators compete to set the price of capacity. (See Figure 1.) However, in price-based schemes (which include the current CRM in the SEM, according to the DDP), generators compete for a share of the total annual revenue awarded by the regulator. In both types of CRM, only those with the lowest cost capacity (existing or new) will remain in the market over the long-term. Both types of CRM will therefore encourage efficient exit – i.e. the exit of the capacity with the highest costs of remaining in operation.

173. Thus, it is not possible to make firm statements about the competitiveness or other performance outcomes of different schemes (especially real schemes) without (a) defining how performance is measured and (b) focusing on the detailed rules of each scheme.

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46 DDP, para 8.4.6.

- **Reason 2: A quantity based scheme "should provide a more proportionate response than a price based scheme to the issues being addressed".[47]**

174. Here, the SEM Committee may be relying on statements in the EU State Aid Guidelines, but in practice there is no analytical basis for this statement. As discussed above, the boundary between price based and quantity based schemes is blurred, to the point where adding a demand curve leads each type to achieve broadly the same outcome in terms of security (quantity of capacity) and efficiency (price of capacity). Therefore, there is no *a priori* basis in theory for this kind of subjective statement about proportionality, and no basis in fact.

- **Reason 3: "a quantity based scheme can be designed more appropriately than price based schemes to mitigate against undue cross border trade distortions".[48]**

175. Although we can see why the SEM Committee might possibly have reached this conclusion, it is not necessarily true and cannot be supported without a detailed consideration of each scheme, which the DDP and IIA lack.

176. The assumption that lay behind the SEM Committee's conclusion may have been that fixing different prices for capacity in neighbouring countries would cause market participants to choose inefficient patterns of flow over interconnectors. In fact, a well-designed capacity payment would have little or no effect on flows (just as it should have little or no effect on the pattern of generation). At peak times, the prospect of earning higher capacity payments might conceivably cause market participants to send electricity from a market with a high energy price to a market with a low energy price. That would represent inefficient arbitrage. However, as discussed elsewhere in this report, the effect on efficiency of generation and consumption would depend on the interventions of the TSOs, not on the inefficiency of arbitrage.

177. Furthermore, pure quantity based schemes may be more prone to abuse by dominant players – and might conceivably cause even more distortion of cross border flows. Experience in the United States shows that the price of capacity in a quantity based CRM is sensitive to generators withholding capacity (or increasing the supply of capacity and demand-side resources). The price of capacity in a pure price based schemes cannot be manipulated in this way and might cause less distortion of cross-border trade.

178. In practice, of course, any scheme will comprise a demand curve (a price-quantity trade-off) and some measures to mitigate market power (such as price caps and floors). Any appraisal of a CRM would have to take these features into account. However, the SEM Committee has failed to specify such features at this stage for most of the CRMs it evaluated. Its evaluation of CRMs is therefore partial and selective.

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47 DDP, para 8.4.7.

48 DDP, para 8.4.8.

- **Reason 4: "as discussed previously and as mentioned by respondents, the requirement for more flexibility in the generation fleet is an important issue which is linked to RES targets and meeting security of supply standards at least cost to consumers".[49]**

179. This reason does not seem to apply to the choice between quantity based and price based schemes, but rather to the definition of eligible capacity. (See for example Batlle et al (2014), pages18-21, on defining the length of the "critical period" over which capacity is measured and provided.) The need to define capacity is common to all the CRMs discussed by the SEM Committee. This "reason" therefore provides no basis for preferring one CRM over another.

- **Reason 5: "the EC and ACER have written on different CRM designs in the last number of years as the issue has gained prominence".[50]**

180. This text does not seem to provide any reason for making a choice.

181. Thus, the DDP and IIA offer no firm reasoning in favour of choosing a quantity based scheme over a price based scheme or one with a demand curve. Overall, the SEM Committee has not provided any objective or convincing reasons for selecting its chosen form of CRM and rejecting others.

6.4. Tendency to Overlook Adverse Effects of ROs

182. The SEM Committee's evaluation of CRMs does not consider several important possible adverse effects of the ROs and how the design would have to be adjusted to reflect these effects. The effects and/or the mitigating features of the design would affect the evaluation of the different CRMs and might have changed the SEM Committee's decision. Their omission is therefore significant.

6.4.1. Contracting and liquidity

183. First, ROs will overlap with some of the hedging that would normally be provided by energy contracts (CfDs). ROs will offer a hedge against market prices above the RO Strike Price.

- To avoid over-compensating for market price risks, market participants will have to design CfDs that only hedge market prices up to the RO Strike Price. (Criterion (4)) This may be a minor inconvenience for new contracts, but will impose costs on holders of existing contracts. It also means that the RO Strike Price should be clearly defined to allow transparent design of CfDs. For example, it might be indexed to the fuel price component of the variable cost of the most expensive generator within the I-SEM (although that is only one rule among many equally transparent rules).

49 DDP, para 8.4.9.

50 DDP, para 8.4.10.

- Setting multiple RO Strike Prices would reduce transparency and segment the CfD market (and would in any case greatly increase the complexity and subjectivity of regulatory decisions on design of the RO).

184. Second, as discussed above, ROs will only hedge consumers against the risk of very high prices if the disbursement of RO rebates is closely coordinated with tariff design. A perfect hedge would require each customer's retail tariff to be tied directly to the DAM price, so that the RO rebate offsets rises in the tariff exactly. If tariffs are set competitively but are not indexed to the DAM price, they may remain stable for long periods (as at present). If RO rebates are passed through to consumers as the events occur, the rebates will – perversely – reduce customer bills and industry revenue during a capacity shortage, a position which may not be sustainable. On the other hand, competitive markets may price in the *anticipated* rebate, rather than pass them through as the events occur. Depending on the design of the ROs any rebates may be returned to consumers as a group, but may be distributed in a manner that customers and regulators regard as inequitable. Accordingly, it is not clear that ROs would remove the incentive for regulatory intervention in periods of high prices and therefore solve the missing money problem.

6.4.2. Impact on generator risk

185. ROs will only provide a tool for managing generators' risks if generators can expect to be generating the same volume as their ROs at peak times when the ROs are called and rebates must be paid. (Criterion (4)) The articles by Cramton and Stoft discuss how the capacity each generator can offer (C_{BID}) should be adjusted for their observed or expected reliability. However, the use of Euphemia creates an additional source of scheduling risk, as discussed elsewhere in this report. Generators may be unable to ensure that they are generating a peak times, because they are unable to configure their offers to achieve the necessary pattern of output, and not because they are technically unable to provide capacity. (Criterion (9)) Such risks would unnecessarily increase the cost of generating (and hence prices to consumers) within the I-SEM with ROs as specified in the DDP.

6.4.3. Selection of a reference price from the Day-Ahead Market:

186. The SEM Committee is proposing to decide the reference price used to settle ROs in the detailed design phase,[51] but the selection of Option 3 strongly suggests that it would be taken from the Day-Ahead Market.[52] However, actual capacity shortages may not be predictable at the day-ahead stage. Prices in the DAM may therefore lie sometimes above and sometimes below the real time value of electricity on the following day. The scheme in Colombia works this way, but the RAs have not considered the impact of using a day-ahead reference price in the conditions pertaining in the I-SEM. It raises the following questions.

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51 DDP, paragraph 8.4.17.

52 See for example DDP paragraph 6.3.35 on Option 3, which links " a high degree of liquidity and transparency in the DAM" to the creation of "a robust reference price". See also DDP paragraph 6.4.27, where the SEM Committee states its view that "Other aspects of the market rules will be developed to encourage participation in the DAM…such as setting the DA price as the strike price for directed contracts and as the reference price for financial reliability options". DDP paragraph 8.4.20 and IIA paragraph 7.2.24 acknowledge the possibility of choosing an intra-day or balancing price instead.

- Will the price in the DAM ever be unable to reflect the true (expected) value of electricity on the following day, because of the price cap in Euphemia of €3,000/MWh? If so, will the ROs solve the missing money problem? (Criterion (2))
- Because of the difficulty of predicting actual shortages, tying ROs to the DAM will sometimes trigger rebates when no shortage occurs. The DAM may also fail to trigger rebates when a shortage does occur. These rebates will flow through to suppliers and, perhaps, directly into consumer bills. A full appraisal of ROs would include consideration of the implications of these mismatches between prices, costs, tariffs and revenues, for generator cash flows and consumer bills, to see if they affect investment incentives and future security of supply. (Criterion (4))
- Selecting the DAM as the reference price seems to be driven by a desire to promote day-ahead trading (rather than any specific concern for security of supply or efficiency). However, participation in the DAM may not be mandatory. A full appraisal of ROs would consider whether the price cap of €3,000/MWh in the DAM will sometimes drive the supply of generation into the (uncapped) ID and BM markets. This development would affect the risk-hedging properties of the ROs for generators, suppliers and consumers. (Criterion (4))

187. These omissions mean that the SEM Committee cannot claim to have properly evaluated the ROs (relative to other CRMs).

6.4.4. Market Power Mitigation

188. Any full appraisal would consider how the RAs will mitigate market power in the auctions for CRMs (and for Reliability Options in particular). For example, ISO-NE, the system operator in New England, operates under strict regulation of offers into its capacity auction. This auction has a floor price and rules on minimum levels of competition – despite being substantially larger (around 36GW) than the SEM. (Criterion (12))

189. These restrictions on pricing in a capacity auction illustrate once more why the distinction between quantity based and price based schemes is a false one, that should play little part in the IIA. It also shows that market mitigation rules can have a major effect on outcomes under any scheme, and would be taken into account in any full appraisal of CRMs. (See chapter 7 for more on this topic.)

6.4.5. Small size of market

190. Due to the small size of the market in the SEM, the price of ROs may still be volatile if investors can anticipate a shortage/surplus of capacity in the year for which ROs are being auctioned. Under current proposals, ROs would be auctioned up to 5 years ahead, but the situation in that year may well be predictable in the SEM, due to the impact of individual no-go investment decisions on a small market.

191. The DDP mentions a reduction in the minimum efficient size of new investment,[53] but that phenomenon seems to apply mainly to renewable energy projects. In that case, the size of

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[53] DDP, paragraph 7.4.12.

individual projects is less important than the total response to changes in renewable energy policy. The price of ROs may still be volatile if market participants anticipate waves of investment in renewable energy starting or stopping, following a change in state-sponsored incentives. In any case, the DDP acknowledges that exit decisions (concerning the existing thermal generation plant) would still have a significant effect on security of supply (and hence on the value of capacity).[54]

192. The purpose of the current scheme was to stabilise revenues in the anticipation of such volatility in energy prices, as a contribution to avoiding the missing money problem. (Criterion (2)) However, the DDP and IIA do not consider whether ROs or any form or CRM will actually achieve that aim, which represents a major omission from the appraisal.

6.5. Conclusion

193. We conclude that the SEM Committee has not justified its proposed decision to select Reliability Options because:

- the SEM Committee has left out significant details from the proposed design of the RO, even though those details are crucial to achieving the RO's intended purpose, so that its evaluation of the RO is *incomplete*;
- the SEM Committee has taken a *selective* approach to describing the effects of each design, specifically by overlooking possible adverse effects of the proposed RO; and
- the SEM Committee has evaluated possible designs for a CRM against criteria that vary from case to case, in scope and in definition, introducing a *bias* into the appraisal and preventing a fair, like-for-like evaluation of the designs.

194. Because of these flaws in the appraisal of the various CRMs, the SEM Committee's choice is not soundly based.

[54] DDP, paragraph 7.4.12.

7. Market Power Mitigation

195. The measures required to mitigate or prevent abuses of market power represent another area which remains to be specified, and which could overturn the SEM Committee's decision.

7.1. Market Power Mitigation in Energy Trading

7.1.1. The need for market power mitigation

196. When the SEM was established in 2007, ESB's large market share caused major concern and led to the establishment of the Bidding Code Of Practice (BCOP). The BCOP obliges generators to submit offer prices that reflect their Short Run Marginal Costs (SRMC), as defined by the opportunity cost of their inputs. Since 2007, the RAs have also directed large generator firms to maintain a portfolio of "directed contracts", i.e. contracts sold off compulsorily by auction, in order to limit their ability to benefit from changing spot prices.

197. In 2010, CEPA studied the state of competition in the SEM at the time and in years to come. In its report,[55] CEPA recommended that the Bidding Code of Practice and directed contracts should remain in force, due to continuing concerns about competition in generation. The SEM Committee accepted CEPA's recommendations in 2012, in the course of approving a horizontal re-integration of two generation businesses owned by ESB.[56]

198. CEPA noted that additional generation had entered the SEM since 2007, and that interconnector capacity had been expanded. However, looking to the future, CEPA found that in many hours ESB would still be "pivotal" – that is. output from its generators would still be required to meet the current level of demand, even if every other generator was operating at full output.[57] A number of these hours arose in the future because output from wind farms will fall to low levels, creating a shortage of capacity, due to natural variation in their output.

199. CEPA also noted that ESB would be pivotal more often, if electricity prices were higher in Great Britain than in the SEM, as the additional interconnector exports from the I-SEM to the British market would then raise demand on generation resources in the SEM, instead of providing a competitive substitute for them. [58]

200. In passing, CEPA also noted that the incentive for generators to withdraw contracts was undermined both by the directed contracts and by the potential loss of a capacity payment. However, CEPA concluded that, in the absence of any major structural changes in the

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[55] CEPA (2010), *Market Power and Liquidity in SEM; a report for the CER and the Utility Regulator*, Cambridge Economic Policy Associates Ltd, 15 December 2010.

[56] SEM Committee (2012a) *SEM Market Power & Liquidity, A SEM Committee Decision Paper*, SEM-12-002, 1 February 2012.

[57] CEPA (2010), *Market Power and Liquidity in SEM; a report for the CER and the Utility Regulator*, Cambridge Economic Policy Associates Ltd, 15 December 2010, page 26.

[58] CEPA (2010), *Market Power and Liquidity in SEM; a report for the CER and the Utility Regulator*, Cambridge Economic Policy Associates Ltd, 15 December 2010, page 28.

concentration of generation, it would still be "appropriate" to retain the BCOP and the directed contracts.[59]

201. Thus, as recently as 2010-12, CEP A and the SEM Committee accepted the need to retain the BCOP and directed contracts in order to mitigate market power. They reached this conclusion despite the entry of competing generators and the increase in interconnector capacity since 2007. They noted that interconnector capacity was not a reliable source of competition because it would add to demand rather than supply, if it flowed from Ireland to Britain at peak times. CEPA also noted that the current capacity payment provided an additional disincentive to the withdrawal of capacity, which would be lost of the capacity payment were abolished.

7.1.2. Market power mitigation in the DDP and IIA

202. The DDP and IIA accept at various points that some measures to mitigate market power will be required. The DDP notes that applying the BCOP will be more difficult – or even impossible – under Option 3, because the structure of offers and bids will not be tied closely to costs. The DDP concludes that the BCOP is unlikely to be maintained, at least in its current form. It says that some ex ante monitoring may be needed, but does not propose any detailed alternative.[60]

203. Under some of the Options, the BCOP may have to be replaced by other measures, but that should count as an adverse effect of choosing those Options. The DDP notes the benefits of transparency in mitigating market power abuse,[61] but does not use this observation in appraising the Options. (We record it as Criterion (12).) Ex ante regulation and/or ex post scrutiny offer an alternative to the BCOP, but neither will ever be as transparent or effective as the BCOP applied to a gross pool with a complex offer price structure. Without such transparent rules, there is no objective way to identify the source of market abuses because there is no way to apportion blame to an individual market participant responsible for market abuses. Oligopolistic competition drives all market participants eventually to adopt similar pricing policies. All market participants will end up exercising market power, but not all such behaviour may constitute an abuse. Competitive pressure may drive small, non-dominant companies to raise their prices just so they match the price of a larger company, or of a market leader. In such circumstances, it may not beclear who is abusing market power (if anyone).

204. The difficulty is well summarised in Wolak (2005), commenting on the attempt by Ofgem in 1999/2000 to introduce a prohibition on market abuse into generator licences.[62] In that paper, he summarises the difficulty as follows:

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[59] CEPA (2010), *Market Power and Liquidity in SEM; a report for the CER and the Utility Regulator*, Cambridge Economic Policy Associates Ltd, 15 December 2010, page 28.

[60] DDP, paragraph 6.4.63.

[61] DDP. Paragraph 5.4.4.

[62] Frank A. Wolak (2005), *Lessons from International Experience with Electricity Market Monitoring*, Department of Economics, Stanford University, 11 July 2005 (available at http://web.stanford.edu/group/fwolak/cgi-bin/?q=node/3)

> "Although a license provision prohibiting abuse of market power appeared to be an effective mechanism for limiting the exercise of market power, the difficulty Ofgem ran into was how to distinguish the unilateral exercise of market power from abuse of market power. It was never able to find a satisfactory way to make this distinction, and many economists including Wolak (2000) [and one of the authors of this report] provided comments stating that this was not possible in a manner that did not introduce significant market inefficiencies."[63]

205. Wolak's point is that, in an oligopolistic electricity sector, it is impossible to identify who is responsible for abusing a market by observing the behaviour of individual companies. Under the SEM at present, the BCOP holds each company is held to a well-defined standard of pricing. Wolak's comments suggest that moving away from the BCOP, as would be required under Option 3, runs the risk of introducing "significant market inefficiencies". Options 2 and 4 contain a pool and would retain the current complex offer price structure. They would allow the RAs and market participants to apply the BCOP in its current form.[64] However, Options 1 and 3 will require the RAs to control market power by adopting alternative measures or by expanding the other measures used at present, e.g. by increasing the volume of directed contracts. We would have expected to see this difference recognised as a disadvantage of Option 3 and an advantage of Options 2 and 4. However, at no point do the DDP or the IIA recognise the resulting advantage over Option 3 offered by Options 2 and 4, either with respect to efficiency (Criterion (2)) or with respect to the transparency of market power mitigation measures (Criterion (12)).

7.1.3. Summary

206. The SEM Committee has reached a draft decision to adopt Option 3, whilst recognising that it will make the BCOP unworkable, without explaining how it will overcome this problem. The DDP and IIA should have identified as a consequence of adopting Option 3 the need to adopt alternative measures for market power mitigation – or to expand other measures already in place, such as directed contracts. This difficulty ought then to have counted against Option 3, relative to Options 2 and 4, but the DDP simply assumes that it will solve the problem in the detailed design phase. The SEM Committee's approach is subjective and prejudicial, and is neither evidence-based nor a sound basis for regulatory decisions.

7.2. Market Power Mitigation in CRMs

7.2.1. The need for market power mitigation

207. Market power in a capacity market is related to market power in the energy market. Generators who control a significant proportion of the capacity on the system are likely to have market power in both parts of the electricity market. A small market with a large incumbent player, like the Irish market, will require market power mitigation mechanisms in both the energy market and the capacity market. Failing to spell out these mechanisms in

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63 Frank A. Wolak (2005), pages 10-11 (Stanford University website version).

64 DDP, paragraph 6.3.47.

advance would run counter to the need for transparency in market power mitigation. (Criterion (12))

208. In fact, the need for market power mitigation may be greater in the capacity market than in the energy market, since the value of capacity is so concentrated in peak periods and is so sensitive to small changes in available capacity. The SEM Committee has argued that the growth in interconnectors in recent years has diversified the sources of electricity supply and reduced the market power problem in Ireland.[65] In relation to the energy market we have already identified issues with this assumption in paragraphs 196 to 201 above. In a CRM, however, the SEM Committee cannot rely on interconnectors to be contributing to supply in peak periods, as they may be exporting to Britain at times of system stress. The risk that interconnectors make no contribution to security of supply at times of system stress is exacerbated by the strength of the penalties imposed at such times for not generating in the British market. The current, and seemingly final, proposals for the British market impose a penalty rate of 1/24th of the market clearing price in the capacity auctions. At DECC's projections of clearing prices around £30/kW, the penalty rate would be £1,250 during a stress event.[66]

209. Possible responses to the reduced reliability of interconnector capacity include reducing, or eliminating, its capacity rating in the centralised auction, which would lessen competition in the CRM compared to the energy market and increase the need for market power mitigation in the capacity market.

210. The specific design selected by the SEM Committee in the DDP needs some market power mitigation. A single, centralised auction provides sufficient opportunities for abusing market rules, as well as for signalling between participants, to merit concern about market power. Accordingly, many similar mechanisms in the United States and the market design for the proposed 2014 capacity auction in Britain include market power mitigation rules which seek to prevent gaming by participants. The designers of US mechanisms take a variety of approaches to mitigating market power, but the following selection shows the kind of rules they have put in place:

- **Minimum Offer Price Rules (MOPR):** In the New England market, bidders may not bid below the Minimum Offer Price and the market monitor scrutinises bids to make sure that buyers are not distorting the market by exerting downward pressure on prices.[67]
- **Insufficient Competition Rules:** The New England market replaces competition with an administrative process if new supplies are needed in a capacity zone and if any market player is pivotal or if offers from new generation amount to less than 300MW or less than twice the new generation required.[68]

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65 DDP, paragraph 8.4.7.

66 DECC(2014), *"Electricity Market Reform: Capacity Market – Consultation on Proposals for Implementation: Government Response", June 2014,* pages 96-97.

67 ISO-NE, Market Rule 1, Section, III.13.1.1.2.8, Qualification Determination Notification for New Generating Capacity Resources. [Downloaded 14 July 2014].

68 ISO-NE, Market Rule 1, Section III.13.2.8.2. Insufficient Competition. [Downloaded 14 July 2014].

- **Resource-Specific Sell Offer Requirements:** Both New England and PJM have strict price caps applied to resources which may be able to exert market power. In PJM, any market participant who satisfies a "three-bidder pivotality" criterion (such that the market could not clear without the capacity belonging to that market participant and two other bidders) may not bid above a strict price cap.[69]

211. Versions of these rules have been adopted in the British market. In Britain, new generators and demand resources automatically qualify as price makers, and may bid in the auction for annual capacity contracts up to a price cap of £75/kW, which represents 1.5 times DECC's estimate of the net cost of new entry. Existing generators may not bid above £25/kW unless they can demonstrate that their costs require them to obtain a price above that level, or else they will close their plant. The capacity markets in the US and in Britain are much larger than the equivalent market in Ireland. Peak demand, for instance, is over 150 GW in the PJM and about 54 GW in Britain; these figures are about 21 times and 8 times, respectively, the level of peak demand in the Irish market, which is only about 7 GW.[70] Withdrawal of a single plant is therefore more likely to move the market price in Ireland than in these other markets, and the fears about a dominant player have not been eliminated since 2007. Consequently, in the Irish context, any centralised auction for Reliability Options will require similar, or perhaps more stringent, market power mitigation mechanisms.

7.2.2. Market power mitigation in the DDP and IIA

212. The SEM Committee argues that the proposed form of Reliability Options will rely on competition as the engine that minimises the cost to consumers. The DDP, which summarises the results of the qualitative impact assessment, claims that Reliability Options provide a:

> "transparent centralised platform for competition that facilitates efficient and coordinated entry and exit signals, whilst using competitive pressures to ensure that consumers don't overpay for adequacy. Centralised reliability options fit well with possible market power mitigation measures in the energy market."[71]

213. It is not clear what is meant by "fitting well" with measures in the energy market. In practice, as discussed in section 7.2.1 above, centralised auctions in the electricity sector tend to be closely scrutinised and run as regulated procurement processes. In the IIA, the SEM Committee discusses competition for CRMs in paragraphs 7.5.40-7.5.45. The discussion betrays an unfortunate degree of selectivity in the appraisal of each CRM.

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[69] PJM Manual 18: PJM Capacity Market Section 5: RPM Auctions, Rule 5.3.1.

[70] PJM (2014), *Peak Demand Forecast Report January 2014*, page 3. Ofgem (2014), *Electricity Capacity Assessment Report 2014*, 30 June 2014, Figure 2 on page 12. SONI and EirGrid (2014), *All-Island Generation Capacity Statement: 2014-2023*, Table A-1 on page 61.

[71] DDP, Table entitled "Summary of qualitative rationale for centralised reliability options against each assessment criteria", underneath para 8.5.2.

214. Paragraphs 7.5.40-41 highlight the problems with short-term price-based CRMs. However, the criticisms raised here apply equally to short-term quantity-based CRMs, a point which the SEM Committee omits. Experience of short-term capacity obligations in the PJM led to the adoption of the current, longer-term scheme.

215. Paragraphs 7.5.42 identifies a feature of the current scheme, namely that the exercise of market power cannot affect total payments in the long run. However, the SEM Committee seems to make nothing of this advantage in its evaluation of CRMs.

216. This oversight stands out particularly starkly, given that the SEM Committee recognises in paragraphs 7.5.43-45 the need for market power mitigation mechanisms to ensure that Reliability Options work effectively:

> "For the quantity-based CRMs (Options 3, 4 and 5), the key area of competition is for the contract award in the form of the initial auction. Given the potential in a small market for anticompetitive behaviour, market power mitigation measures may be needed as part of the detailed auction design.
>
> Market power mitigation measures are part of quantity-based CRMs in other markets, e.g. in the US and in the proposed GB scheme. This can include bidding rules, which can relate to minimum offer prices to deter inefficient exit or maximum bids (e.g., for existing plant). These rules could also be targeted at a subset of the market where market power has been identified as a concern.
>
> Crucially, centralised reliability options offer a transparent public auction that is held on behalf of all demand in the market so as to exploit economies of scale (th[r]ough the concentration of liquidity) with the objective of increasing competition, and creating a level playing field for market participants. International best practice and experience strongly argues for a centralised auction process on competition promotion and market power mitigation grounds"[72]

217. The IIA does not claim that Reliability Options are immune to the market power problems encountered in other "quantity based" capacity auctions. However, the DDP does not reflect the concerns about market power and quantity based CRMs set out at this point in the IIA. The DDP provides no description of market power mitigation mechanisms in the market for Reliability Options, leaving such matters entirely to the detailed design phase.[73] Instead, the DDP conveys the impression that Reliability Options operated through centralised auctions are transparent and competitive. The DDP notes that transparency fosters competition, but that finding is not always supported by economic theory or practice. Many centralised auction processes deliberately hide information about the current set of bids from participants to prevent anticompetitive behaviour. For example, the capacity market rules for Britain mandate a descending clock auction in which market participants only receive limited information about the bidding process. The auctioneer will not reveal the identity of the remaining bidders during the bidding process and will round the volume of excess supply at

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72 IIA, paras 7.5.43-45 (Footnotes omitted).

73 DDP, paragraph 8.4.23.

any given price to the nearest GW.[74] These rules are intended to prevent transparency from becoming an aid to tacit collusion.

7.2.3. Summary

218. In summary, the SEM Committee adopts different views in the DDP from those expressed in the IIA. The DDP repeatedly describes Reliability Options as "market-based" and implies that the process of awarded and managing them will be solved by transparent auctions. The IIA, on the other hand, notes that conduct of an auction will require a major regulatory intervention to mitigate market power.

219. These conflicting approaches betray a fundamental confusion about the implications of Reliability Options for competition. If the regulator has to tell major market participants what to bid, the outcome of a centralised auction for Reliability Options will not be a product of competition, but rather the outcome of regulatory decisions about key parameters. The DDP is therefore misleading, because it contrasts "market-based" Reliability Options with other CRMs that are supposedly more heavily regulated. In practice, international practice shows that none of the auction-based mechanisms operate without significant regulatory intervention to constrain bidding behaviour.

220. Any regulatory intervention intended to counter market power in a competitive market runs the risk of adverse effects, because it may also distort or prevent pro-competitive bidding behaviour. No impact assessment would be complete unless it examined the regulatory interventions required by each kind of CRM and assessed the associated risks of adverse effects. By overlooking the need for regulatory interventions in auctions of Reliability Options, whilst recognising that need for other CRMs, the SEM Committee has biased its evaluation of the different mechanisms.

7.3. Conclusion

221. Nothing suggests that market power problems have been eliminated since 2007, or will be eliminated in the near future. However, according to the RAs, it will be safe to abandon the current BCOP, despite not knowing what will replace it under Option 3. We conclude that the SEM Committee's willingness to abandon the BCOP represents a subjective leap of faith, or a prejudicial bias in favour of Option 3, rather than a conclusion based on evidence, and that the SEM Committee should consider what alternative measures or expanded measures (such as a greater volume of directed contracts) would be made necessary by the adoption of Option 3.

222. Measures to mitigate market power are also likely to be necessary in any centralised auction of capacity market instruments in the I-SEM. The SEM Committee recognises this need in the IIA, but ignores it in the DDP, frequently describing Reliability Options as "market-based",[75] whilst highlighting the degree of regulatory intervention in other CRMs. This

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[74] *The Capacity Market Rules 2014*, chapter 5, rule 5.5.18, page 55.

[75] See DDP, 1st paragraph on page 12, paragraph 8.4.12 on page 73, and also Decision 4 ("The I-SEM CRM will be based on Reliability Options") on pages 14 and 76 of the DDP.

selectivity in describing the impact of market power mitigation has biased the SEM Committee's evaluation of CRMs for the I-SEM. As a result, we conclude that the SEM Committee has no reliable basis for assessing CRMs, or for selecting Reliability Options, with regard to their impact on competition.

8. Summary of Conclusions

223. Overall, we conclude that no-one can have any confidence that the SEM Committee has reached the right decision on High Level Design for the I-SEM. (Chapter 2)

224. In relation to the methods of appraisal used in the DDP and IIA, we conclude:

- that the decision to select Option 3 is not based on a full understanding of its implications and is biased by the focus on a limited set of each Option's features (Chapter 3); and
- that the SEM Committee's appraisal of the Options and Capacity Remuneration Mechanisms is not based on equal application of objectively defined criteria, but on the selective use of subjectively defined criteria and *ad hoc* considerations. (Chapter 4)

225. With regard to the selection of energy trading arrangements (Chapter 5), we conclude:

- that the SEM Committee's description of the Options is incomplete and in some cases erroneous;
- that SEM Committee's appraisal of the Options is selective, subjective and prejudiced; and
- that the SEM Committee's draft decision is not soundly based on evidence or analysis.

226. With regard to the selection of a Capacity Remuneration Mechanism (Chapter 6) , we conclude that the SEM Committee has not justified its proposed decision to select Reliability Options because:

- the SEM Committee has left out significant details from the proposed design of the RO, even though those details are crucial to achieving the RO's intended purpose, so that its evaluation of the RO is *incomplete*;
- the SEM Committee has taken a *selective* approach to describing the effects of each design, specifically by overlooking possible adverse effects of the proposed RO; and
- the SEM Committee has evaluated possible designs for a CRM against criteria that vary from case to case, in scope and in definition, introducing a *bias* into the appraisal and preventing a fair, like-for-like evaluation of the designs.

227. In relation to market power within energy trading (Chapter 7), we conclude that the SEM Committee's willingness to abandon the BCOP represents a subjective leap of faith, or a prejudicial bias in favour of Option 3, rather than a conclusion based on evidence, and that the SEM Committee should consider what alternative measures or expanded measures (such as a greater volume of directed contracts) would be made necessary by the adoption of Option 3.

228. In relation to market power within the capacity market (Chapter 7), we conclude that the SEM Committee has no reliable basis for assessing CRMs, or for selecting Reliability Options, with regard to their impact on competition.

229. We therefore conclude that the SEM Committee's draft decision on a High Level Design for the Single Electricity Market is unsound.

Appendix A. EU Target Model – Key Elements

230. The following elements of the EU Target Model, as encapsulated in ACER guidelines, are the most relevant to the SEM Committee's consideration of a new High Level Design for the SEM.

A.1. Market Coupling

231. The *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity* ("CACM Guidelines") issued by ACER in 2011 require market coupling at the day-ahead stage. The phrase "market coupling" means that cross-border transmission capacity is made available at the day-ahead stage all across Europe "implicitly" through trades arranged on power exchanges, rather than being explicitly auctioned as transmission capacity between two networks in neighbouring countries.[76]

A.2. Cross-Border Transmission Contracts

232. ACER's CACM Guidelines also require that market participants have access to option contracts for cross-border risk hedging.[77] These option contracts may in principle be Financial Transmission Rights (FTRs) or Physical Transmission Rights (PTRs), as long as any PTRs are subject to Use-It-Or-Sell-It (UIOSI) provisions. The NRAs in the two countries concerned may decide which method to adopt, but may not mix the two methods "on the same border". They must auction off any cross-border rights using a common European or regional platform. In practice, since any implicit auction of cross-border transmission capacity includes a physical constraint (either ATC or "flow-based"[78]), there is very little difference between (1) auctions of energy plus uncommitted capacity covered by FTRs and (2) auctions of energy plus PTRs released under the UIOSI rule.

A.3. Gate Closure

233. The CACM Guidelines also foresee an intra-day market that enables market participants to trade energy as close to real-time as possible, through implicit auctions where feasible.[79]

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76 ACER (2011), *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, 29 July 2011, section 3.1, page 9: "The CACM Network Code(s) shall foresee [i.e. provide] that TSOs implement capacity allocation in the dayahead market on the basis of implicit auctions via a single price coupling algorithm which simultaneously determines volumes and prices in all relevant zones, based on the marginal pricing principle. The implementation shall take into account the role of the power exchanges (PXs) and shall require the harmonisation of day-ahead bidding deadlines." [footnotes omitted]

77 ACER (2011), *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, 29 July 2011, section 4.1, page 10.

78 ACER (2011), *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, 29 July 2011, section 2.1, page 6.

79 ACER (2011), *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, 29 July 2011, section 5, page 11.

A.4. Balancing by TSOs

234. The role of TSOs in balancing is set out in the *Framework Guidelines on Electricity Balancing* ("Balancing Guidelines") which ACER issued in September 2012.[80] ACER foresees TSOs collaborating to achieve the following objectives:

- "safeguarding operational security;
- fostering competition, non-discrimination and transparency in balancing markets;
- facilitating wider participation of demand response and renewable sources of energy;
- increasing overall social welfare and efficiency;
- promoting cross-border balancing exchanges."[81]

235. More specifically, the Balancing Guidelines require TSOs to collaborate on achieving an efficient joint despatch across all systems, using the principles of a (least-cost) merit order to minimise the cost of balancing.[82]

[80] ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012.

[81] ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012, section 2.1, page 12.

[82] "TSOs are responsible for organising balancing markets and shall strive for their integration, keeping the system in balance in the most efficient manner and following the general objectives defined in Section 2.1 of these Framework Guidelines. To do so, they shall work with each other in close cooperation and coordinate their activities as much as necessary.…the Network Code on Electricity Balancing shall define that exchanges of balancing energy are to be based on a TSO-TSO model with common merit order list. In this model, TSOs share their balancing resources and optimise their activation in order to minimise the cost of balancing..." ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012, sections 2.1 and 3.3.2, pages 12 and 17.

Appendix B. Market Design Criteria

236. This appendix sets out the design criteria that any electricity market should meet, to ensure that it underpins efficient investment in generation capacity and demand-side response (in the long term) and efficient operation of generation and consumption of electricity (in the short term). Together, these aims combine into a requirement that electricity markets should encourage least cost production (i.e. productive efficiency) and set prices that reflect marginal costs (to promote allocative efficiency).

B.1. Market Infrastructure

237. Any “electricity market” consists in practice of a number of interlocking arrangements for trading electricity (markets) and for issuing generators and demand-side resources (DSR) with command-and-control instructions (scheduling and despatch). These arrangements must fit together in a way that meets certain operational criteria, specifically:

1. **Market design must permit secure operation of the system by the TSO, so that generation always matches demand (“security of supply”); and**
2. **Market pricing rules (in conjunction with any capacity remuneration mechanism) must allow total generation capacity that is efficiently selected (investment) and operated (despatch) to recover its costs.**

238. Some command-and-control arrangements will inevitably be required (because certain events happen too fast, or have too short a duration, to be managed through market transactions). However,

3. **“Gate closure”, when central despatch and administrative pricing take over from decentralised contracts and trading, should occur at the latest possible stage before delivery.**

239. Centralised arrangements will apply to some or all of the following (with reasons in brackets):

- Ex post imbalance charges (essential in all regimes)
- Real time spot market (integrated with central despatch)
- Day ahead markets (possibly integrated with central scheduling, but also required by EU harmonisation requirements on market coupling)
- Forward markets (if central intervention is required to promote the market and justified by net benefits over decentralised trading)

240. Some provision for centralised, administrative and ex post pricing of imbalances is a feature of every functioning electricity market. It is by definition impossible to set up contracts for individual imbalances in advance. Instead, imbalance pricing arrangements provide a contractual (or, at least, legal) basis for pricing imbalances when they occur. Imbalances provide an alternative source of, or outlet for, generation to all other electricity markets – one MWh more/less purchased by contract converts (independently of any adjustment to output or consumption) into one MWh less/more on the trader’s imbalance account Hence, the value of a contract is the avoided cost of an imbalance. This cost also defines the value of

generating an extra MWh and the cost of consuming an extra MWh (independently of any other adjustment to contracts) The price put on these imbalances therefore supports the prices in all these other electricity markets and provides the final incentive to generate or consume electricity in real time. It follows that electricity market design processes must give detailed attention (using the criteria set out here) to the prices for ex post imbalances, as well as the pricing algorithms used in other electricity markets.

241. Two further principles arise as corollaries to the desire to attract efficient investment:

4. **The market design should allow traders to maintain a contract portfolio that at all times hedges the price of their expected output, and to change their contract position if their expected output changes.**
5. **The electricity market infrastructure, the format of offer/bid prices and market pricing rules should allow non-discriminatory access by all generation and DSR technologies.**

242. Electricity market prices - for real-time, intra-day, day-ahead and other trades and for imbalances – vary widely and somewhat unpredictably. In contrast, a large proportion of generators' costs are fixed, and for many the variable component depends on international fuel prices. This combination of revenues and costs imparts a high degree of risk to long-lived investment in generation. Investors need to manage.this risk, e.g. to limit the maximum loss that a generator can incur due to adverse movements in prices and costs. Efficient market designs should not prevent traders using contract to manage these risks. The inability to use contracts may drive investors towards particular industry structures (e.g. vertical integration) or technologies (e.g. thermal plant whose variable costs are correlated with electricity market prices). Such biases prevent efficient choices.

243. Ideally, electricity markets should permit all *possible* technologies to enter the market and to be selected purely on the basis of their costs and risks. In practice, electricity market design can usually only ensure that all *known* technologies can participate efficiently – including likely future technologies and demand-side participants.

244. To achieve this aim, offer/bid price formats must accommodate multiple cost structures on a non-discriminatory basis (avoiding technology-specific rules, where possible). In addition, the timing of data submission and gate closure should be consistent with the ability of individual generators to match their output to their sales. This criterion requires careful consideration of: (1) the dynamic characteristics and "non-convex" (e.g. start-up) costs of thermal plant; and (2) the (un)predictability of output from wind or solar plant. In addition, the market infrastructure must provide a basis for efficient use of (3) interconnector capacity, which takes account of the varying costs of supply (or demand) from other markets.

B.2. Market Organisation

245. The organisation of decentralised contract markets or voluntary exchanges can be left to the participants. Centralised market arrangements (including ex post imbalance pricing) should meet the following design criteria.

246. Centralised markets should adopt the same principles as efficient, decentralised markets both in matching supply with demand and in setting the price. In particular, efficient markets

select offers to supply in increasing order of cost and bids to buy in decreasing order of value, so as to maximise the net welfare of the market clearing outcome. Efficient markets then set prices equal to the marginal cost of supply (or, in some conditions, the marginal value of demand[83]). These principles can be expressed as follows:

6. **The market or despatch algorithm should select offers (and bids) in an efficient least-cost "merit order".**
7. **Prices should reflect marginal costs in the geographic market concerned, i.e.: (1) the "system marginal cost" for markets covering the whole system; (2) the "local marginal cost" of individual generators operating within a local market (e.g. for generators that are "constrained on" or "constrained off" and running out of merit).**
8. **Prices should reflect marginal costs over the timescale of decisions associated with trading in the market concerned.**

247. Principle 8 relates to the calculation of marginal costs (and hence prices) when cost functions are "non-convex", meaning that generators have to incur some costs (start-up, hourly no-load, etc) in order to generate any output.[84] These costs are marginal to total output over some period (a few hours, a day, or longer) even though they cannot be attributed directly to any individual unit of output. Because they cannot be assigned directly as a marginal cost of any individual unit of output, they must be allocated by a rule to several different units of output.

248. The design of the rules used to allocate non-convex costs complicates the operation of any market, but is essential to meet the following criterion, which promotes efficient despatch and allows generators to manage their risks:

9. **Pricing rules should offer market participants the assurance that:**
   a. **generators will receive a price above their marginal costs when they generate;**
   b. **generators will generate whenever the price is above their marginal costs;**
   c. **generators will not generate if the price is below their marginal costs; and**
   d. **equivalent rules apply to the acceptance of offers submitted to markets;**
   e. **equivalent (but obverse) rules apply to the supply of, and bids from, despatchable DSR.**

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83 This pricing rule applies when supply hits a constraint, such as a step change in production costs or an absolute limit on output. In these cases, the system marginal cost is defined by the cost of depriving consumers of supply, rather than the cost of increasing supply. In most cases, however, efficiently matching supply with demand sets the marginal cost of supply equal to the marginal value of demand.

84 When costs are "convex", each successive unit of output costs more than previous ones. In these conditions, setting the market price equal to marginal cost – i.e. the cost of producing the last unit of output – guarantees that the price will cover the cost of producing all units of output. However, if costs are "non-convex", this simple rule may not result in a price that covers all the costs of producing output to serve this market. Such an outcome does not encourage efficient generation and pricing rules in many electricity markets provide for the inclusion of the "non-convex" costs within a measure of each generator's offer price, before identifying marginal costs.

249. This is a rather more general statement of the principle set out on page 88 of the Draft Decision, which refers to a book by Steven Stoft. The extract quoted there covers criterion 9a, but not 9b or 9c.

250. It is a corollary of this principle that market participants should be able to understand how prices are set, and that there should be no ad hoc or subjective intervention in price-setting, but this principle is worth stating separately:

10. Price-setting rules should be transparent (i.e. they should use objective data in pre-defined formulae).

251. Note that these criteria represent a restricted set which takes a number of design parameters for granted, such as the duration of the settlement periods to which separate prices apply.

B.3. Market Power

252. The principles set out above apply to any market, but implementing them may be difficult if the designers cannot rely on the forces of competition to impose certain outcomes. If certain players possess a high degree of market power that is expected to persist for a long time,[85] achieving the principles above may require the adoption of measures to mitigate market power. These measures should also abide by certain principles, to ensure that they do not hinder the achievement of the others (or at least to minimise their negative impact), and to ensure that they do not discourage market participants from behaving in a competitive fashion.

11. Measures to mitigate market power should be transparent (i.e. use objective data in pre-defined procedure).

253. For example, the current Bidding Code Of Practice (BCOP) requires market participants to submit offer prices that, in summary, include cost items incurred over a daily timescale, and valued at their opportunity costs. Applying these rules is relatively straightforward in the current SEM, because the format of offer prices matches the structure of production costs at most generators. Sometimes, disputes have arisen over the relevant timescale for including cost items and over the concept of opportunity cost, but these disputes can be resolved in an objective fashion which provides guidance for future decisions by market participants. If the new I-SEM defined offer prices in simple €/MWh terms, the same procedure could not be applied objectively without additional rules, because individual generators would have to make subjective commercial decisions about the allocation of their "non-convex" costs (see above).

254. Finally, it seems desirable to limit any market power to the market where it is found, and to prevent its extension into other markets through vertical integration by ownership, contract or other means. For example, given that there is a dominant producer in the Irish generation

[85] Individual producers (or buyers) may possess market power at particular times, but the motivation for intervention is a fear that such market power will persist and will not be eroded by the decisions of competitors. The ability to earn high profits by exercising market power is in practice the normal means of providing an incentive for efficient entry by new competitors. Prohibiting all such profit opportunities would remove the incentive for innovation and eliminate any effective role for competition.

sector, it would seem desirable to prevent that producer from extending its market power into forward contract markets or into the retail electricity market.

12. The existence of market power in one market should not preclude competitive entry or supply of services in a related market.

255. In the specific case of the Irish electricity market, there may be a need not only for measures to mitigate market power in generation, but also for measures to protect or promote competition in forward contract markets and retail electricity markets.

Appendix C. Discussion of Interconnector Capacity Rights

256. The DDP contains a discussion of physical and financial transmission rights (PTRs and FTRs) on the interconnectors in section 6.4, but it contains a number of errors. This appendix sets out some of the key points made in the DDP, along with corrections.

C.1. PTRs, FTRs and Nominations into the I-SEM

257. "Though FTR Options are equivalent to PTRs with UIOSI, FTR Options have the key advantages of not requiring nominations of physical forward contracts into the I-SEM or harmonised physical nomination rules with neighbouring zones in the region or at pan European level." (DDP, 6.4.11)

258. This statement misrepresents both the ease of implementing FTRs and the difficulty of implementing PTRs on the interconnectors. Making FTRs work requires a major effort to synchronise day-ahead markets, in order to permit an implicit auction. Synchronising day-ahead nominations of interconnector flows does not appear to present any greater problems. Gate Closure occurs at or after the day-ahead stage in both Ireland and Great Britain, and so does not represent a constraint on the time at which traders fix flows over the interconnectors.

C.2. Relationship Between PTRs and the Day Ahead Market

259. "Given the size of the I-SEM market relative to interconnection capacity, issuing PTRs would risk 'locking out' 20% of the market (i.e., the entire capacity of the cross border lines relative to the size of the all island system) from the day ahead energy market clearing process." (DDP, 6.4.12).

260. This statement seems to be untrue, or at least not to be true under all the Options. Under Option 3, for instance, PTRs could require holders to finalise their use of interconnector capacity at the day-ahead stage, by offering a given output to the DAM. They would do so as the DAM is the "exclusive" route to file physical notifications.

C.3. Netting Off (Offering Capacity in the Reverse Direction)

261. "FTR Obligations would allow for netting of interconnector capacity, thereby increasing competition between generators and suppliers in both markets" (DDP, 6.4.13)

262. This statement is misleading in two senses. First, netting is possible not only on the capacity covered by FTRs, but also on capacity covered by PTRs. In other words, suppose that an interconnector offers 1,000 MW of capacity in either direction, and that PTR holders schedule 1,000 MW from East to West. The TSO can immediately offer West to East capacity of 2,000 MW, just as the TSO would do through an implicit auction with FTRs.

263. Second, providing this flexibility facilitates efficient arbitrage between the two markets, but it is not clear how it increases competition. Netting is really just one form of UIOSI/UIOLI rule, and offers no additional advantages for competition. Netting does not increase the real net supply of electricity into either new market – each new supply created by netting is offset by a new demand and so leaves the balance of real supply and demand unaltered.

C.3.1. Unnamed and possibly irrelevant sources of evidence

264. "A consultancy report to the European Commission from 2011 recommended that FTR Obligations be adopted throughout the Target Model mainly because of the competition promoting attributes described in the previous paragraph." (DDP, para 6.4.14)

265. The recommendation in a consultancy report is not really compelling or objective evidence in favour of any particular solution. The DDP should say who wrote the consultancy report and whether they represent an independent opinion or are merely one of the SEM Committee's advisors. (We cannot check these points, as the reference in footnote 17 does not work.)

266. Moreover, the DDP should recognise that the European Commission did not accept the recommendation, since the EU Target Model accepts the possibility of using both FTRs and PTRs. If there is any guidance towards using FTRs, the DDP would have to show that it was motivated by the desire to promote competition, since such effects appear to be a myth.

C.3.2. Speculation and subjective interpretations

267. "FTRs [may] replace PTRs on an increasing number of interconnections across the EU in the coming years…" (DDP, 6.4.15)

268. "FTRs (Options and Obligations) are the preferred model for allocating transmission capacity and hedging congestion in many markets in the United States…FTRs are far from untested in market designs and are part of the FERC Standard Market Design." (DDP, 6.4.16))

269. The first of these arguments is just speculation about the future systems in Europe. The second is a subjective interpretation of the facts, since there is no evidence that FTRs are "preferred", or what that really means. The FERC Standard Market Design mentions FTRs, but was rejected by many market participants and operators, so that it does not have any real effect. It is certainly not the US equivalent of the EU Target Model.

C.3.3. Failure to recognise drawbacks of FTRs

270. "The SEM Committee is not aware of any evidence that there are any material drawbacks to implementing FTRs." (DDP, 6.4.16)

271. The SEM Committee has overlooked the fact that use of FTRs effectively prevents capacity in neighbouring countries from serving the Irish capacity market. Whenever cross-border trade in capacity has been allowed, the only way to make it effective has been to limit trade to generators who possess PTRs on the interconnector. These PTRs contain physical scheduling rights required to ensure that generators in neighbouring markets can and will provide energy when needed. The SEM Committee has not considered this possibility and so is forced to rule out cross-border trade in capacity (in favour of a compromise position on interconnector capacity).

C.3.4. Confusion of efficient trading and efficient usage

272. "Furthermore, in order for the all island market to integrate further into the European Internal Market it is important that the existing interconnectors are used optimally.…The SEM Committee believes that FTRs best achieve these objectives." (DDP, 6.4.17)

273. This sentence provides another indication of the SEM Committee's confusion over the difference between efficient arbitrage, and efficient usage. Even if FTRs promote more liquid day-ahead trading (which is doubtful), they will only foster efficient day-ahead arbitrage. Efficient use of interconnectors depends on the scope for real time adjustment to cross-border flows, through intra-day markets and balancing markets (inter-TSO cooperation).

C.3.5. One-Sided Use of Equivalence

274. Paragraph 6.4.18 of the DDP sets out the ways in which FTRs are equivalent to Physical Transmission Rights with a "use it or sell it" condition ("PTRs+UIOSI"). The SEM Committee uses this equivalence to support the use of FTRs. However, it might just as well support the use of PTRs with suitable (UIOLI/UIOSI) conditions that make unused capacity available to others in real time. These arguments seem therefore to add nothing to the case in favour of FTRs.

Appendix D. Review of the Qualitative Assessment

275. Section 5.5 of the IIA sets out a “qualitative assessment” of the four Options. It suffers from the same problems of subjectivity and potential bias outlined above. The following comments therefore identify specific problems in relation to the individual assessment criteria used in that section.

D.1. Internal Electricity Market

276. Section 5.6 of the IIA opens with the “five pillars” of the EU Target Model, but then fails to apply them rigorously or consistently to all the options. For example, three of the “pillars” are “day-ahead market coupling”, “intra-day continuous trading” and “cross-border balancing”. These pillars represent specific institutions – but the appraisal does not consider whether each Option contains these institutions, but rather how well these institutions will perform under each option, by reference to rather vague criteria. For instance, in the section on Option 1, paragraph 5.6.4 considers the liquidity of day-ahead and intra-day markets and their impact on the “effectiveness” of day-ahead and intra-day market coupling. However,

- there is no definition of “effectiveness” for *day-ahead market coupling*;
- there is no explanation of the relevance of *intra-day market coupling* (which is *not* one of the “five pillars”); and
- there is no consideration of the nature, existence, effect, “effectiveness” or efficiency of *cross-border balancing* (which is one of the “five pillars”).

277. The remainder of this section (paragraphs 5.6.1 to 5.6.21) is full of such selective and subjective assessments, using undefined terms. The first sentence of the final paragraph states that all the options are compliant with the requirements of the EU target model. In principle, that sentence ought to comprise the full conclusion on this section. However, the next sentence says that Option 3 is superior to the other Options, because of its impact on liquidity, without saying why this criterion is relevant for – in fact, dominates – the assessment of compliance with the EU Target Model. In fact, it is merely further evidence of a selective, biased and subjective appraisal process.

D.2. Security of Supply

278. Once again, this section (paragraphs 5.6.22 to 5.6.40) contains one short statement that answers the question. Paragraph 5.6.24 reports the statement by EirGrid that it can maintain system security under any of the four Options. That is a definitive response. This section of the IIA contains however a protracted discussion of the arrangements for day-ahead trading and nominations, without explaining why that is relevant to the criterion of security of supply. Paragraph 5.6.34 praises Option 3 for the liquidity of the DAM, as advantageous “in terms of longer term security of supply” (because it provides reference prices for forward trading). However, paragraph 5.5.5 states that Option 3 requires further development and specification in the areas of “incentives for market participants to participant in the DAM” and “additional measures to support forward market liquidity as spot market liquidity on its own will not guarantee the development of forward market liquidity.” Either the authors of the IIA did not notice the contradictions between these paragraphs, or they have simply adopted a prejudicial

view of Option 3, ignoring any potential obstacles to favourable outcomes under Option 3 whilst highlighting such obstacles under other Options.

D.3. Competition

279. The over-riding impression given by this section, paragraphs 5.6.41 to 5.6.55, is that it is based on very little understanding of competition policy and the associated economics. Competition policy is about making sure that market institutions support competition among producers in a way that benefits consumers. Instead, paragraphs 5.6.43 (Option 1), 5.6.46 (Option 2), 5.6.49 (Option 3) and 5.6.52 (Option 4) all focus on liquidity and "routes to market" as a means of favouring certain market participants.

280. Paragraph 5.6.43 concludes that Option 1 would require "liquidity promoting measures". Paragraph 5.6.49 says that liquid centralised markets are a key feature of Option 3, providing "competitive but equal routes to market for all players", but this appraisal overlooks the need under Option 3 for measures to promote (forward) market liquidity mentioned in paragraph 5.5.5.

D.4. Environmental

281. The difficulty of applying this criterion is set out clearly in the first (unnumbered) paragraph of this section. It states that "a market cannot be designed specifically around renewable generation", but then concedes that "the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables." The latter statement just means in practice that any market that is not "designed about renewable generation" will be rejected. However, in practice, little of this section is related to renewable generation or more general environmental goals. Much of the text concerns matters such as liquidity and reference prices, which have little to do with the environment per se. This discussion assumes implicitly, without saying so, that the market must be designed to support the current instruments of government environmental policy.

282. Paragraphs 5.6.60, 5.6.63, 5.6.65 and 5.6.70 assess whether flexible resources will receive proper recompense under each Option. This question arises from the prediction that rising volumes of renewable generation will require a concomitant increase in the level of flexibility offered by thermal generation. However, this question overlaps with the previous discussion of security of supply (where EirGrid said that all Options were compliant) and the later discussion of efficiency (which deserves greater emphasis than it receives).

D.5. Equity

283. This section, from paragraph 5.6.75 to 5.6.93, suggests that, having adopted equity as a criterion, the authors found it hard to define equity as a separate standard. The "equality of access" described in paragraph 5.6.75 is indistinguishable from "competition". Paragraph 5.6.76 proposes to review the "delivery of an allocative[ly] efficient outcome where prices reflect marginal costs", which overlaps directly with "efficiency". As a result, perhaps, the authors are drawn into making a number of subjective and unsupported statements on unrelated matters.

284. For instance, paragraph 5.6.78 says that Option 1 “places the greatest reliance on competitive market structures underlying the market”. There is no analysis to back up this statement, nor any real explanation of what is meant by “places the greatest reliance on….” The same paragraph also states that “In the absence of such a competitive structure, it places reliance on adaptations to achieve competitive outcomes”, but that statement is true of all the Options – indeed, of all markets everywhere. It does not therefore help to evaluate Option 1 relative to the others.

285. Paragraph 5.6.79 says that a portfolio player “may” choose to use its own sources of generation, even if cheaper generation is available from others, without saying why such behaviour would be economically rational under Option 1 - and without explaining why it would not occur under other Options. Paragraph 5.6.80 identifies transactions costs as a problem under Option 1, but does not say whether centralised markets operating under the other Options would (a) reduce transactions costs or (b) merely hide them and impose them on others.

286. Much of this section consists of vague or speculative statements about each of the Options, on a shifting range of topics that defies any attempt to make a comparison between the Options.

D.6. Stability

287. Paragraphs 5.7.2 to 5.7.10 profess to consider the stability of each Option. The brief definition at the start of the section refers to the desire for arrangements to be “stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.” In practice, any market will be stable throughout its own lifetime; what matters is the long term stability of markets over the lifetime of investment projects. To apply such a criterion, the IIA would have had to define what kind of long run stability was important to investors, by reference to the remuneration offered for long term investment.

288. Instead, the IIA discusses the extent of any differences between the institutions in each Option and (1) the current SEM and (2) electricity market institutions in the rest of Europe. That approach is bound to favour an Option whose institutional design sits between the current SEM and other markets. However, electricity market designs change all the time and the current round of reforms intended to implement the EU Target Model cannot be regarded as the final round. Any assessment of the long run stability of institutions (as opposed to the returns to investors that they offer over the long run) would have to assess the internal pressure for change, by identifying potential inefficiencies and inconsistencies, rather than merely by noting the differences from other (temporary) institutions.

D.7. Adaptive

289. This criterion seems to be motivated by the desire to make changing the rules easy for bureaucrats, which conflicts with the desire for stability expressed under the previous criterion. In any case, the appraisal seems highly selective and to apply different definitions of the criteria to different Options. For instance, paragraph 5.7.11 accuses Option 1 of being difficult to adapt to local circumstances, “if there is a liquid DAM and IDM…on the organised, centralised European markets”; this condition conflicts with all the rest of the assessment, which ascribes to Option 1 specifically a *lack* of liquid markets. Paragraph

5.7.14 says that Option 2 will be “vulnerable to external change” because it differs from other markets, but does not explain why it would need to change, or why changes would be expensive if they involved adopting other systems that already existed. Paragraph 5.7.16 seems to suggest that Option 3 will be highly “vulnerable to external change” like Option 2, because it is tied to European systems, but then concludes perversely with a positive finding that the governance arrangements should accommodate any changes required by local conditions. This contrasts with the discussion of Option 4 in paragraph 5.5.17, which identifies a difficulty in having to amend the model to reflect changing European requirements, rather than a benefit in having a model that already reflects local conditions.

290. Depending on the Option being considered, therefore, this section adopts different and conflicting attitudes to future changes driven by European and local requirements.

D.8. Efficiency

291. The discussion of efficiency in this section is only cursory and broadly repeats the consideration of markets, scheduling and despatch set out in other sections of this report. Once again, paragraphs included in the appraisal of an individual Option make statements of a positive or negative character which affect the reader’s view of that Option, whereas in practice they apply equally to all the Options. For instance, paragraphs 5.7.23, 5.7.26 and 5.7.30 point out for Options 1, 2 and 3 that the impact of non-energy factors (i.e. reserve – and other ancillary services) on physical nominations will depend on the arrangements for procuring them. It is not clear why this statement is missing for Option 4. In reality, it applies to any electricity market, and so plays no role in selecting one design from many.

292. The summary in paragraphs 5.7.33-35 does not in practice evaluate all four options by the criterion of efficiency. Instead, it asserts once more that Option 3 is efficient, albeit only by reference to day-ahead integration of interconnectors. (Once again, it overlooks any other aspects of efficiency, such as the effect of intra-day and real-time adjustments.) Therefore, this section does not add anything to the (rather scant) discussion of efficiency in earlier sections of the IIA and in the DDP.

D.9. Practicality/Cost

293. As in other sections of the IIA, paragraphs 5.7.36 to 5.7. 52 highlight the difficulties involved in implementing Options 1, 2 and 4, whilst allowing for further work in the detailed design stage to make Option 3 overcome criticisms from respondents. This part of the appraisal is therefore as selective and biased as any in the IIA.

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