Integrated Single Electricity Market (I-SEM)

Measures to Promote Liquidity in the I-SEM Forward Market

Consultation Paper

(SEM-16-030)

Power NI's Response

29h July 2016

Introduction

Power NI welcomes the opportunity to respond to the Consultation Paper (SEM-16-030) published by the Regulatory Authorities (RAs) in relation to Measures to promote liquidity in the I-SEM forward market.

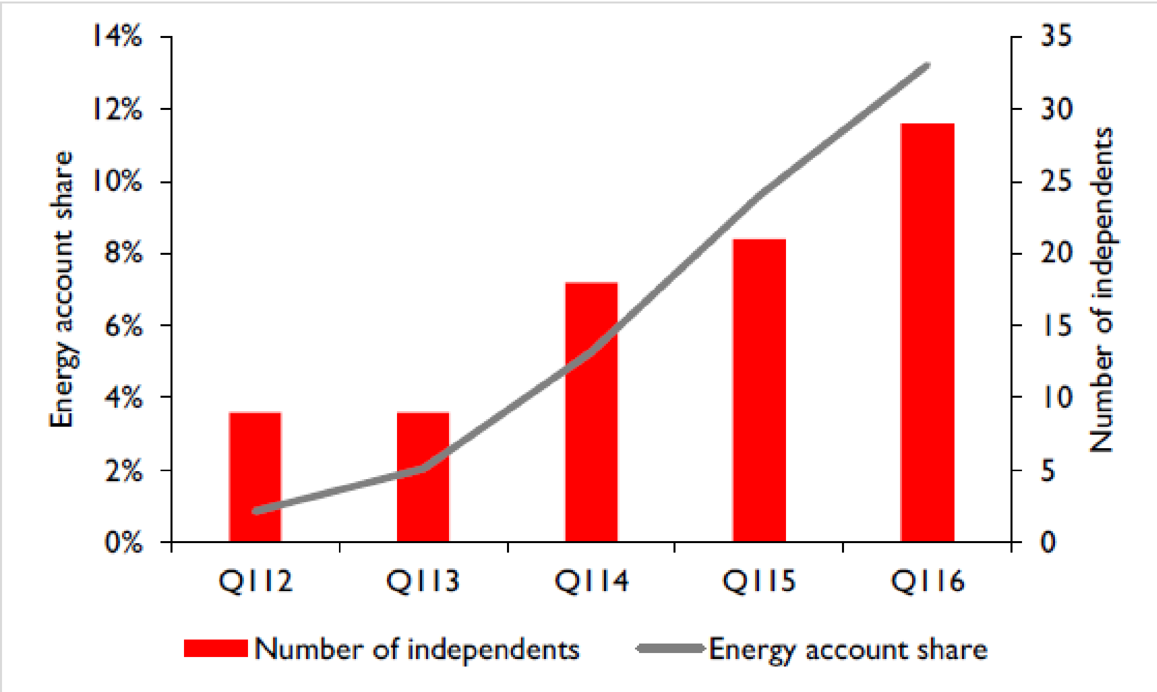
In support of our response, we have attached a report prepared by NERA for the Viridian Group, which is the paper "Response to the SEM Committee's Consultation on Liquidity", and refer to it throughout this paper.

It has been a consistent feature of our responses to previous consultations to highlight the vital importance of a functioning and liquid forward market to delivering tangible benefits to the consumer and underpinning retail competition. Power NI's predominantly domestic customer base and their elected representatives have clearly communicated a desire for tariff stability, which can only be delivered through an effective and liquid forward market. In addition, lack of access to hedging product is a fundamental barrier to entry in the retail market which will have long term adverse effects on competition if not addressed, and the introduction of the new market represents an ideal opportunity to tackle the problem. We welcome the RAs assertion in this paper that the systemic liquidity issues should be addressed by regulatory intervention and we can see merits in each of the proposals outlined in the paper, at least at a conceptual level; however, it must be considered that certain elements of the proposals have the potential to have significant negative impacts that must be weighed against the benefits of a marginal improvement in liquidity. The most notable of these is the removal of ring fencing on ESB which we evaluate in the following section.

We believe the need to follow through on forward market intervention is clear; liquidity in the SEM has been perennially poor in comparison to any other relevant market and it has been widely acknowledged, both in the consultation paper and in the preceding workshops for market participants, that there is nothing inherent in the new market design that is likely to significantly improve this. A continuation or even worsening of the liquidity outlook post October 2017 is detrimental to the interests of consumers. Firstly, unhedged suppliers will need to be able to pass through the risks of wholesale market volatility to customers, thereby reducing tariff stability in a market where consumers clearly value cost certainty. This is important for consumers across the board from the domestic market (note the adverse response to multiple regulated tariff changes in 2008, or the ultra-competitive market that has arisen in fixed price contracts in GB), through to SMEs & LEUs where demand for fixed price contracts has long been a feature of that market. For suppliers and those without large physical assets to naturally offset this risk, the inability to hedge and the difficulty in passing through increased costs in a timely manner has the potential, in extremis, to result in bankruptcy; a scenario that would have significant implications for the entire market.

Given this possibility, it is clear that poor forward market liquidity is a significant barrier to entry in the retail market and in the long term will favour large vertically integrated (VI) participants who are more able to absorb these risks through their natural hedge. Improved access to hedges for suppliers in the GB forward market, delivered by OFGEM intervention, has been a key facilitator in the growth of independent suppliers (see chart below[1]).

Number of independent suppliers and account share of the domestic energy market



Source: Cornwall Energy

Market share for the independent suppliers (grey line in the table above) has grown significantly since the introduction of Secure & Promote (S&P) in March 2014, having almost tripled over that period, and is continuing to grow, with the benefit of providing competition for the VI incumbents in the short term, and driving innovation in products and services in the longer term, something which will be absolutely vital in realising the benefits of technology (e.g. smart metering) in delivering the flexible, low carbon, competitive electricity system that policy makers and regulators across the board are trying to achieve. Note that we explore the impact of S&P when considering market makers, as the recent report published by the CMA on their energy market inquiry, reveals that the market access rules had a positive impact, but that market maker obligations had a limited impact on liquidity.

The proposals in this paper should be viewed in this context, that is, their importance for the functioning of the retail market. However, the solution to delivering the

[1] Cornwall Energy, Energy Spectrum 513, Mar 2016

liquidity and market access needed to realise this, cannot simply be a transpose of the GB intervention, as it was very specific to the market structure in question. In GB, there are a number of VI players with generation portfolios and large independent generators, with a concern that independent suppliers did not get access to the same hedging products that these firms were able to trade internally. In Ireland, the position is different to GB with a dominant generator (ESB) and one larger supplier (Electric Ireland (EI), as per 2015 analysis in Table 9 of the paper). Therefore, the issue is that almost no supplier has the ability to trade their exposure internally (at least not fully), with a generation market dominated by one player who, considering the potential impact on their retail business (i.e. a loss of market share like that of the Big Six above), are clearly disincentivised from fostering a truly liquid forward market. Accordingly, in the context of the Irish market, Power NI is a smaller scale supplier when compared to EI.

Vertical Integration

The paper raises the prospect of the removal of ring fencing on ESB as a condition of the interventions proposed in Options 3, 4 and 5. While we can see positives in elements of these proposals in terms of addressing the liquidity problem, the implications of this condition are such that we could not accept any of them.

ESB's position in the Irish market is not comparable to the examples used in the paper, in particular with GB. The analysis in the consultation paper on both generation and supply volumes puts into perspective their dominance. For this reason, the interventions proposed should be focused on ESB, and not in exchange for the removal of ring fencing. We expand in further detail in the relevant sections, but neither of the two forms of intervention proposed requires vertical integration for ESB. For a Forward Contract Selling Obligation (FCSO), ESB will have a dominant market share in any forecast generation scenario, and their diverse portfolio will be much less vulnerable to changing market conditions than independent generators; therefore there is a clear justification to mandate a greater pro-rata obligation on them in comparison with standalone generators. The higher obligation on ESB would not be arbitrary or discriminatory, but reflective of the portfolio benefit they have relative to other generators, so should not be imposed as a trade off for removal of ring fencing.

For the other intervention proposed, Market Maker Obligations (MMO), the consultation paper itself asserts that vertical integration is not necessary for the imposition of an obligation; it is purely a function of the financial strength i.e. balance sheet, of a party. By this definition, ESB and Electric Ireland rank number 1 and 2 in the Irish market so vertical integration is not required to bring them into scope.

In clear contrast to this logic, the paper dismisses ring fencing within the Viridian group as "limited". While we agree with the point that it is not relevant in the context of liquidity, we believe the same applies to ring fencing of ESB, as outlined above.

While any assessment of ring fencing should be taken outside of this process, we believe that the on-going ring fencing of the Viridian Group is disproportionate and discriminatory and that in a competitive high risk market other measures should be looked at to provide the assurances the RAs get from ring fencing which given the market shares of the Viridian Companies can only be assumed to be concerns about cross subsidisation.

Marginal improvements in liquidity, which are the scope of the interventions suggested in the paper, while welcome, are not a justification in themselves for making such a significant change to the current market structure. For instance, the maximum bid-offer spread proposed for the market maker obligation would be an improvement, but a fairly limited one in comparison with today's market (see our analysis in the section on SEM liquidity), and it is not necessarily the case that this will improve the traded volumes significantly. Hence, the benefits are very unclear. On the other side of the equation, there is a lack of analysis on the impacts of the removal of ring fencing, particularly on the retail markets. The NERA report provides comment from the previous review of the ring fencing arrangements:

CEPA further found that consumers would benefit from the continued existence of the ring-fence:

> "Our analysis has shown that, in the presence of the SEM pool system, retail suppliers do have a degree of ability to offer at least monthly fixed price contracts to its consumers, but that it would remain a challenge for the retail supplier to offer longer term fixed price contracts. This, combined, with the key lesson from BETTA that contract liquidity in electricity is problematic both to investigate, and to design remedies for, would argue for a continuation of ring-fencing for a further period."[2]

The circumstances have not changed since 2010. The ring-fence was good for the market and consumers in 2010 and it remains good for the market and consumers today. Any proposal to remove the ring-fence would have to demonstrate either that changes in market conditions since 2010 had invalidated the original case for ring-fencing, or that removing the ring-fence was necessary to achieve certain benefits that were not considered in 2010.[3]

Any major change such as this should be done on the basis of a substantive review of the costs and benefits, and not as part of this consultation process, and for this reason alone, Option 3, 4 and 5 are impossible to accept, regardless of any possible liquidity benefit.

Liquidity in SEM

[2] CEPA (2010), *Market Power and Liquidity in SEM - A report for the CER and the Utility Regulator*, 15 December 2010, page 71.

[3] NERA Response to the SEM Committee's Consultation on Liquidity p15

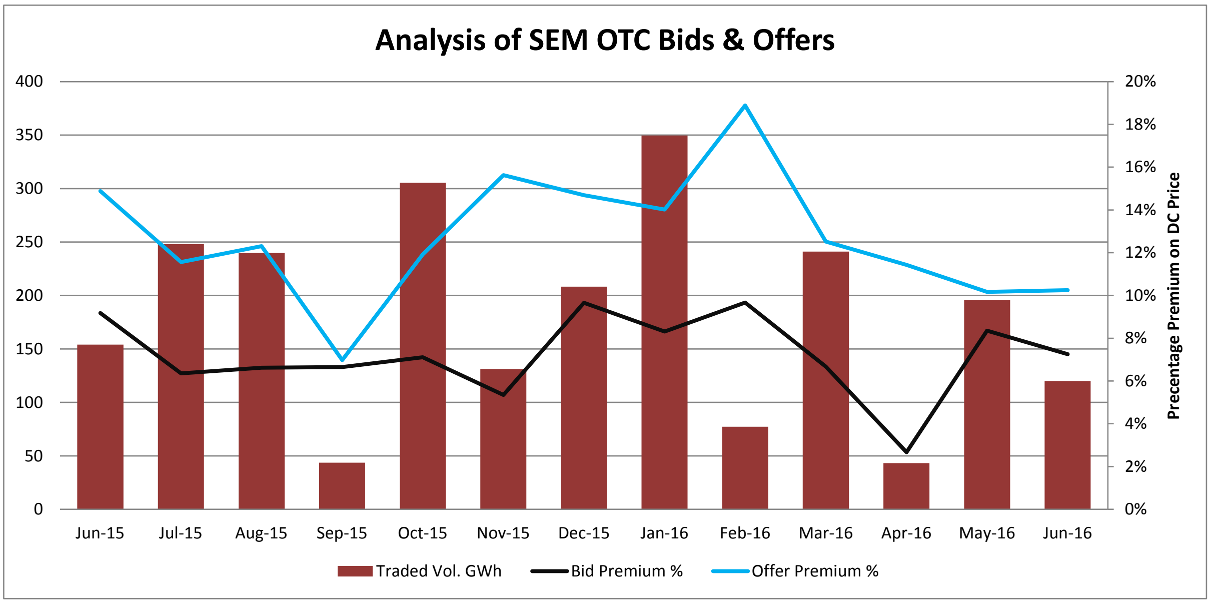
The paper is generally correct in its assessment of the nature of the problem experienced in the SEM forward markets; these issues have been common themes raised widely in previous consultation processes, as well as the recent market participant working groups on liquidity. The Regulatory Authorities (RAs) assessment that there are asymmetric incentives to trade CfDs between suppliers and generators would appear to be a central issue. We agree with this analysis, however it cannot be argued that there has not been a financial incentive for generators to trade CfDs as the premiums in relation to expected spot price are significant. The chart below shows the % premium, averaged across baseload products, bid over and above the Directed Contract (DC) price, by suppliers in the last year. It is clear that suppliers have bid consistently at a premium to the expected spot price and while the consultation paper suggests this may be a function of the "risk premium", there is evidence to suggest otherwise. The NERA report notes that, "academic studies of forward markets (and of electricity forward markets in particular) find evidence of positive, zero and negative risk premiums, giving no reason to suppose that a positive risk premium is the natural order in the I-SEM".[4] In spite of the potential to capture this extra value in supplier bids, only a small proportion of the generation market is being traded in the forward market, a clear sign that there are deeper structural issues.

The % premium in generator offer prices is plot on the same chart, and it is clear that the bid-offer spread is also significant, averaging over 5%. This spread is higher than those seen in other relevant liquid markets, for example in GB where bid-offer spreads have generally been below 1% for a forward curve extending at least 2 years forward[5]. It is interesting that in their initial response to the CMA inquiry in GB, responding from their position as an independent generator in the GB market, ESB[6] asserted, "Market participants face large buy sell spreads and poor volumes in…forward markets", and yet the data in GB (and the analysis of the CMA) shows the forward market in GB is significantly ahead of the current position in SEM.

[4] NERA Response to the SEM Committee's Consultation on Liquidity p15

[5] CMA Final Report Appendix 7.1 Liquidity (68, pg 21)

[6] ESB Initial Submission to CMA investigation, https://assets.publishing.service.gov.uk/media/53f1c31240f0b62d98000019/ESB_response_to_IS.pdf



On the supplier side, the incentive to trade is strong; a hedging portfolio is essential to mitigate the risks of volatile cashflows on the buying side while supplying customers at a relatively stable price. It has been contended, both in the consultation paper and in discussion at the working groups, that suppliers have a number of hedging options outside of the SEM CfD market, including proxy hedging through gas and other commodities, or directly through financial institutions. We discuss proxy hedging in more detail later in this response, however as acknowledged by the paper, it is not a perfect hedge to SEM, and it is difficult for small and non-asset backed players who do not already have a footprint in these markets to trade cost effectively. Also, the perennial lack of liquidity in SEM CfDs is such that no bank or other financial counterparty has an interest in trading them; at no stage has Power NI seen any evidence of CfDs being traded where the party does not have a physical position or interconnector capacity holding. So, in reality, participants with a net demand exposure in the market, and particularly smaller suppliers without any generation capacity, are dependent on a liquid forward market to provide the hedging products they need. There is an array of evidence to support the notion that there is strong demand for hedging products from suppliers across the board;

- DC volume is always sold, largely in the original allocations.
- PSO volume is generally always sold, even though significant volumes are concentrated into 2 auctions, which is not ideal.
- Bid prices on the OTC are consistently higher than expectation of spot prices, i.e. suppliers have been prepared to pay a premium to hedge their risk (just not any premium).

However, despite the demand from suppliers, generators (or for that matter, financial players) have not traded significant volumes of CfDs, as the analysis in the paper (for 2015) shows, outside of DC & PSO contracts, traded volumes were limited. Our most recent analysis would indicate that the situation in the SEM has certainly not improved, and if anything, is deteriorating. In 2016 to date, only 1,087 GWh has been traded through the OTC platform – in comparison with 2,314 GWh traded over the same period in 2015[7]. Trading has decreased to the extent that in April, Tullet Prebon raised the prospect of having to close their OTC platform down as they are not covering their operating costs. Many of the risks identified in the paper such as scheduling risk, increasing intermittent generation and market concentration act as a disincentive to generators to trade in the current market design, and it is not clear that the new market design will remove these barriers without intervention.

It is possible that increased volatility in spot prices, caused by moving from a pool price set with strictly defined bidding restrictions to a voluntary market such as the Day Ahead Market (DAM), with more freedom in bidding strategies, could act as an incentive for generators to trade CfDs to have greater certainty over their margins. However, we consider that there should be significant incentive to do so in the current market and that is not the case, so it is unlikely that the move to DAM will in itself deliver a liquid forward market, and it is likely that the other changes to the market outlined below will act as a further disincentive to trade.

Amongst the other new features of the market that may impact forward liquidity that are noted in the paper, there is limited scope for an improvement in liquidity. The switch to Financial Transmission Rights (FTRs), should make interconnector trading simpler than in the current market, however historically the full volume of import capacity contracts has been traded anyway, so it is unlikely to drive an increase in traded CfD volumes. In addition, it is possible that there could be further headwinds to reduce the appetite for CfD trading. For example, the impact of, and any interaction between CfDs and Capacity Remuneration Mechanism Reliability Options (ROs) is unclear at this stage, potentially with differences for plants with and without ROs. The voluntary nature of DAM means that generators may see value in trading some of their volume outside of DAM, and hence may want to limit their exposure to DAM-indexed CfDs. Also, the uncertainty around EUPHEMIA outcomes is unlikely to give generators confidence in their scheduling pattern (at least in the transition period), and this would particularly affect a standalone generator in comparison with a large generation portfolio. Finally, factors not related to the market design, such as the continuing increase in wind capacity will continue to erode the possible volumes that generators could offer to the market.

Liquidity in I-SEM

Given all of these factors, it is a reasonable conclusion that the introduction of I-SEM in itself will not address the forward liquidity issue. Hence, it must be welcomed that the RAs now consider that intervention in the forward market is necessary for the many reasons outlined. In terms of the measures outlined in the paper, the

[7] Tullet Prebon OTC Trading Results
http://www.tullettprebon.com/irelandpowerauction/otc_trading_info.aspx

proposals would seem to largely cover the most obvious interventions; addressing barriers to trade, and either an obligation on generators to sell volume or on larger participants to act as market makers, and we offer our analysis of each in the subsequent sections.

While we welcome that DCs will continue largely in their current form from a liquidity point of view, it must be noted that the relaxation of bidding restrictions and increased complexity of the I-SEM spot markets result in increased potential to exercise market power. Given that DCs are an existing intervention for spot market power, it must continue to be priced independently on an analysis of expected spot price. If DCs were opened to an auction mechanism, or something similar, ESB could receive a higher price, and there could be incentives on EI to bid for larger volumes, which would remove the positive effect that DCs currently have in the market. As noted in NERA's report, changing DCs from allocation to auction undermines their ability to mitigate market power for two reasons[8]:

1) EI will be able to bid higher prices than any other supplier, since the price in a contract between ESB Generation and EI is merely a transfer price, with no implications for the profitability of the group as a whole.
   a) This statement applies whether or not the two businesses are ring-fenced. EI will be able to bid for a large share of the DCs, without fear of over-payment.
   b) Contracts between ESB Generation and EI do not reduce the incentive for ESB to exercise its market power, again because the contracts have no impact on the profitability of the group as a whole.
   c) This approach will therefore reduce or invalidate the role of DCs in mitigating ESB Generation's market power.

2) Even if EI is prevented from taking part in the DC auctions, auctions for DCs will not settle at competitive market prices. Instead, the prices bid by other suppliers will anticipate the effect of ESB's market power.
   a) DCs are a derivative contract whose value depends on the (expected) price of the underlying product, namely physical energy traded in the short term reference market.
   b) Under current proposals, generator bidding will be less transparent in the I-SEM than in the SEM, but the constraints on ESB's bidding are weaker – mostly *ex post* monitoring.
   c) If ESB has market power over the reference market used to settle DCs, and is expected to raise prices in that market, the value and auction price of DCs will rise by the same amount.

[8] NERA Response to the SEM Committee's Consultation on Liquidity p31

DCs will not therefore provide any kind of disincentive to the exercise of market power by ESB.[9]

Therefore allocating DCs via an auction mechanism will not have positive liquidity benefits for the market as a whole as volumes will remain the same, however as they undermine the mitigation of market power for which they were introduced, we strongly support retention of the current price setting arrangements.

DCs have been a vital source of hedging for suppliers, and this is reflected by the consistent uptake of available volume, hence we would urge the RAs to implement an adjusted DC process for I-SEM as soon as possible after this consultation process. Suppliers are now facing a situation where they will have no opportunity to purchase CfDs beyond Q3 17, and as we move closer to that period, unhedged positions will result in tariff volatility for customers. It is vital DCs are offered as soon as possible, via an interim mechanism if this is required, and there should be no delay for the implementation of any platform or other trading arrangements. In the medium term, given the question over the commercial viability of central trading providers, every opportunity should be explored as to how DCs could be traded via the same counterparty and credit arrangements as with all other CfDs to support the platform with guaranteed trading.

Another element of DCs (and all of the options proposed in the paper) that could be changed to best meet the needs of suppliers is the length of the forward curve. Achieving the desired tariff stability is in part dependent on the volume of hedging available, which this paper seeks to address, and also on how far ahead a supplier can hedge. A reasonable hedging strategy to meet customer requirements would require forward contracts traded up to 2 years ahead of delivery. In GB, 29% of volume traded is for delivery beyond year ahead[10], showing that parties are disposed to trade in these timeframes, and this should be an ambition of any proposed intervention. It is a requirement driven by customers' demands to be able to trade in these time frames. As well as providing tariff stability to domestic and SME customers, I&C customers are now frequently tendering for multi-year contracts with flexible hedging strategies. The ability of only a few players to have the flexibility to trade the underlying commodities over this period has an adverse effect on competition in this market. It should be possible to extend the current DC methodology to support trading over a longer forward time frame (ideally 2 years), as

[9] This argument does not deny the ability of DCs to mitigate market power. Once in place, DCs with fixed prices diminish the benefit to ESB of raising prices in the reference ("spot") market. However, the situation changes if ESB can influence the prices written into the DCs. Before each auction takes place, ESB has an incentive to threaten to raise future spot prices, in order to drive up the prices that suppliers bid for DC contracts. In order to make that threat credible, ESB has every incentive to show that it can and will raise spot prices as much as possible. Other measures to mitigate market power may not completely remove ESB's ability to raise spot prices in this matter. However, any leeway to raise spot prices will be reflected in the prices of DCs.

[10] CMA Final Report Appendix 7.1 Liquidity Table 3 (adjusted to remove trades less than 1 month ahead of delivery for refinement of a physical position)

the current system already trades up to 15 months forward. This applies equally to all proposed interventions.

On a similar note, the PSO auctions could also be reformed to support liquidity; firstly, by trading via central mechanisms thereby supporting an exchange and maintaining consistent credit requirements, and secondly, by distributing the available volume along the forward curve. The PSO auctions would then represent another opportunity for participants to arrive at a forward price curve (as opposed to the current system, which is focused on quarter ahead only), which would provide a useful benchmark for any of the other interventions proposed, given that pricing is going to be an important aspect of each of them. It also aligns with supplier needs, as discussed regarding DCs, and provides more opportunities to buy, which will be vital in any case where we do not have a continuously traded market. To continue to offer only short term liquidity would be a missed opportunity to capitalise on a significant proportion of existing traded volume.

The following sections of our response focus on the detail of the proposed interventions presented in the consultation paper.

Trading Mechanism

There has been fairly consistent agreement across previous consultations and working groups that the mechanics of trading have represented a barrier to liquidity in SEM. Negotiating any bilateral trading agreement is a lengthy and potentially costly process, which could be replaced by a single standard agreement with a central counterparty, giving access to the entire pool of liquidity; this would be a significant improvement for small suppliers and remove a barrier to market entry. Progress on a standard master agreement across the market should be a target regardless of the involvement of any central counterparty. Collateral requirements have also been a difficult issue to negotiate bilaterally with a range of credit terms in the market currently, with larger players able to dictate terms. The introduction of central collateral arrangements in certain circumstances would be a positive development, which would be reinforced if there was netting with other markets in the I-SEM; this has the potential to make forward trading more attractive to all parties. All opportunities for credit netting currently available in SEM (e.g. across group entities) should be maintained in I-SEM to maximise benefits.

The benefits of centralised trading could be significant if they help deliver increased liquidity in the forward market, however it is reasonable that consumers should not be expected to underwrite a commercial exchange. As proposals from potential providers are made, they should be made available to all market participants to complete a full analysis of the costs and benefits to ensure proposed fees and terms are widely accepted. If, as is the case in other markets, the trading fees are small relative to the traded contracts it is likely to remain a net benefit to suppliers.

In terms of how the RAs can best facilitate exchange development, after the current investigation phase, the key is to ensure all liquidity where possible, whether by intervention such as DCs or those new obligations proposed, or any other CfD trading, is transacted through the central mechanisms on commercially acceptable terms. In addition, the RAs must continue to monitor that market access is maintained for suppliers, e.g. through a clearing bank, and that the requirements of an exchange do not place new barriers to entry. Market access for all should be a key deliverable of this process; note in a following section on MMO, that the CMA recognise improved market access has been the key success from liquidity interventions in the GB market.

At all stages of implementation, all market participants should have the opportunity to have an input into the development of the rules and the platform to ensure it meets the requirements of participants. We are being asked to provide our views on centralised trading at this stage without having the detail on the arrangements e.g. for collateral, so our support for central trading mechanisms is conditional on developing a commercially acceptable solution that meets the needs of participants. For instance, our preference is to retain the flexibility to use Letters of Credit or cash as collateral, as deemed appropriate, so if the only option is daily margining of cash, this would be a downside, and also potentially act as a barrier to entry (and hence negative for liquidity). The solution of clearing banks acting as intermediaries to a central clearer is also fine in principle, however, information currently available in relation to the DAM/Intra Day (ID) markets suggest that there will be a limited number of clearing banks available; there needs to be a joined up approach to encouraging financial institution entry to I-SEM, and forward market proposals should form a part of that.

One theme touched upon in the consultation paper, without any specific details, is that of transparency and reporting of forward trading. The market failure identified in this paper, could be more pronounced in the initial period with the uncertainty surrounding the new trading arrangements but this may improve and it may be that some of the interventions may be scaled back or replaced in future, but for any future determination on liquidity provision there needs to be an appropriate level of transparent and publicly available reporting with regular assessment by the RAs. This should be the case with any of the proposals, and if there were none. It also makes it important that all trading mandated by a new liquidity obligation would be better to be (subject to the commercial caveats set out above) transacted through the central market mechanisms. The RAs should implement their own transparent reporting as REMIT is not sufficient to monitor anti-competitive behaviour in I-SEM. As noted in the NERA report, “REMIT may oblige traders to report their trades, but withholding supply to raise prices requires a decision not to trade, which would not be reported”[11].

[11] NERA Response to the SEM Committee’s Consultation on Liquidity p5

Forward Contract Sell Obligation (FCSO)

As a general concept for intervention, Power NI is supportive of FCSO. By reducing the market to a series of regulated auctions, it may not deliver liquidity according to the RAs definition in the paper (that is, parties must be readily able to trade out of positions), and it does not address any of the underlying structural problems in the market (e.g. ESB dominance). It is this structural problem that we see as the greatest obstacle to a functioning and liquid forward market. The NERA report outlines 2 key competitive advantages which ESB have over other parties in trading forward contracts;

First, as a vertically integrated company, ESB has less incentive to participate in the forwards market because the risk that its supply arm faces (ie. that the cost of purchasing at spot electricity prices rises, whilst its revenues are fixed) is largely hedged by the risk that its generation arm faces (ie. that its revenue at spot electricity prices falls, whilst a large share of its costs are fixed).

- The CMA notes that the "Big 6" companies in Britain are also vertically integrated, but that they still trade in the forward markets, because each company's generating shape is unlikely to match the shape of its demand (eg. EDF primarily operates baseload plants, whilst Centrica primarily operates peaking plants).[12]

- In contrast, ESB has a diverse portfolio of generators and is more able to match the shape of demand, meaning it has little incentive to hedge in the forward market.[13]

Second, ESB has market power in the generation industry, and as a result has an informational advantage over other potential traders (a case of "informational asymmetry" which is not addressed by REMIT).[14]

While an FCSO does not address this fundamental structural issue, it does go some way to addressing supplier's needs for hedging products and improve market access, by tackling the reluctance of generation to trade in the forward timeframe which is symptomatic of the asymmetric incentives and structural market power issues discussed. This aligns with one of the stated focal points of intervention (p. 37 of consultation paper), i.e. promoting an increase in availability of hedging products, and it is this aim that should be the deliverable in this process, rather than an increase in an arbitrary measure of liquidity. It also prevents existing vertically

[12] CMA (24 June 2016), *Energy Market Investigation: Final Report – Appendix 7.1*, para. 105

[13] The diverse nature of ESB's generation is indicated by the selection of the shape for the DC portfolio, which comprises baseload/mid-merit/peaking contracts in the proportion 2/1/1. (SEM-16-030, p50) Other generators in the I-SEM possess generation that only operates in part of the merit order. ESB also possesses generators using a wider range of fuels, by merit of the fact that some generators only own one plant and therefore use only one fuel (or possibly gas and distillate).

[14] NERA Response to the SEM Committee's Consultation on Liquidity p11

integrated players from internal hedging and reducing the opportunity for that volume to be traded in the forward market.

It is understandable that generators, and particularly those with smaller market shares, will be concerned about the additional risks that the obligation, as currently proposed, would place on them, and there are a number of ways that the proposal could be refined that will deliver a better outcome for all parties. However, in general, the market will still have a net shortage of forward hedging products, and it could reasonably be expected that on average this will generate a premium over expected spot prices, which in a functional market you would expect to act as a commercial incentive to trade this volume, regardless of any obligation.

One element of the proposed design in the consultation paper which requires adjustment is the calculation of the total FSCO obligation, for two reasons; firstly, the obligation should be set based on what generators could reasonably be expected to provide, as opposed to some arbitrary assumption on a supplier's hedging strategy, and secondly, the assumptions as presented are not representative of an ideal hedging strategy. It is fair to expect that import FTRs will be a source of hedging for suppliers in I-SEM, however it is unclear from the paper as to how the aggregate figure of 6.34 TWh is arrived at – this number is going to float (in the same way that any of the generation assumptions will) with market conditions, and it is a fair assumption that there will be greater convergence between GB and I-SEM prices in the future (the fundamental basis of the DAM) and hence exports will become more prevalent.

The other assumption in the sample hedging strategy that we would contend is the inclusion of proxy hedging. Suppliers would not consider proxy hedging as part of an ideal strategy were there sufficient hedging products to cover their demand requirements, and if it exists in the current market, it is purely a last resort as a result of the identified deficiencies. Proxy hedging is only prevalent in the SEM to bridge the current CFD liquidity issues faced so should not form part of a set hedging strategy for suppliers in the context of I-SEM liquidity.

Within the calculation of the obligation volumes, the deduction of 20% for proxy hedges using gas prices is excessive and is more likely to be used by participants that already have an exposure in those markets e.g. trading Gas or Carbon.

Significant basis risk exists between gas prices and outturn power prices and is likely to increase in future, e.g. as GB prices have more of an impact through market coupling, and as more wind comes onto the system. While in the forwards timeframe there may be a broad correlation between medium to long term price movements in gas and power contracts, at delivery (or day-ahead, the price that we want to hedge) the correlation deteriorates significantly, as short term non-commodity effects such as plant availability, wind output etc. come into play[15].

Footnote 2 of the Consultation Paper recognises observed deviations between gas and electricity prices in 2009. This is a perfect example, since it is precisely these deviations that make any combination of fuels a higher risk option for hedging power prices. Gas and electricity prices are likely to diverge whenever there is a surplus of gas and/or a shortage of generation capacity. It is precisely on those occasions, when a proxy fails to track the desired price, that electricity market participants need protection from spot price risk. Close correlations at other times provides limited compensation for exposure to these occasional risks. Experience has therefore shown that gas contracts represent a riskier instrument for hedging electricity price risk compared to CfDs.

For this reason, Ofgem recognised in their impact assessment for the S&P intervention that reliance on proxy hedging was not appropriate; “For physical players, this so-called ‘dirty hedging’ may not be sufficient. The future correlation between these commodities may change, especially given higher intermittency. The gas market also does not provide access to peak products. Suppliers may find this approach to managing their risks particularly unappealing, especially as a firm using gas to hedge a physical power position would still have to purchase power at some point”[16]

An alternative and fairer method of considering the total obligation of the FCSO would be to examine what each generation entity could reasonably be expected to provide. It is simple in the scenario presented to look at a set of historical Market Scheduled Quantities (MSQs) and apply an overall percentage obligation to trade forward to arrive at a total and set individual obligations, however in reality, any determination of future MSQ at this level will be subjective and unpredictable. Therefore, it is reasonable to expect that obligations should be based on a range of market forecasts with either a deterministic scenario approach, or a probabilistic method. Generator’s obligations, both at a total and individual level should then be based on their forecast minimum MSQ (or preferably, reasonable confidence interval e.g. 95th percentile MSQ). It is reasonable to expect that a generator would perform an analysis of this nature before deciding what volume to sell in the forward market and by carrying this out in a fair and transparent way, the RAs would be applying this intervention in a way that better meets their own assessment criteria in Chapter 10 (i.e. better targeted, flexible to market changes and transparent, if the analysis is made available).

One would expect that carrying out an analysis such as this would reveal that outputs for non-diversified (i.e. independent, mid-merit or peaking) generators would

[15] Our analysis shows a 46% correlation between NBP day ahead gas and average daily SMP in 2015

[16] Ofgem, Wholesale power market liquidity: final proposals for a Secure and Promote licence condition – Draft Impact Assessment, 12 June 2013 p11

be more volatile and unpredictable in comparison with ESB, due to its larger and more diversified fleet. Hence, the percentage obligation of a base forecast MSQ on ESB would be larger than for smaller players, which would be a fair reflection of the increased uncertainty and commercial risk these parties face in offering CfDs. The higher obligation on ESB would not be arbitrary or discriminatory, but reflective of the portfolio benefit they have relative to other generators, and hence there is no requirement for an arbitrary increased obligation on them, in exchange for removal of ring fencing, an act that has the potential to be more harmful than any of the benefits of the proposed interventions. It also needs to be considered how often this analysis needs to be reviewed in light of changing market conditions; an approach similar to the DCs where a model is set up and assumptions updated on a quarterly basis seems sensible dependent on practicality for the RAs. Regardless, there must be some regular update to the forecasting to ensure obligations are reflective of a generator's ability to meet them.

Another element of the FCSO design proposed in the paper is the mix of products that could be offered. Similar to the previous argument on the size of the obligation, setting a product mix in this way is subjective and will undoubtedly place more risk on smaller and standalone generators. For this reason, it should be left to the individual generators how they discharge their obligation, provided they sell the required MWh volume in each auction, they should be able to shape this using the standard agreed products to best meet their own forecast profile. It should also be noted that generators will retain the current flexibility of selling higher than obligated volumes in an auction entirely at their own discretion, on terms that are not subject to the RAs reserve price.

A further key concern with the FCSO design as proposed is the length of the forward curve itself. As noted in our comments on DCs and PSO, customers (and hence suppliers), need to be able to hedge over a longer time horizon to arrive at the price stability or fixed price contract they desire. Obligating generators to sell a large proportion of their forecast volume in year-ahead auctions will undoubtedly kill off any trading beyond the 12 month time horizon, which would be a critical failure of the design currently proposed. This is another example of where the desired outcome of 'liquidity' is poorly defined, as the problem is not solely solved by MWh volume traded.

The auction itself is proposed in the paper to be monthly. While it is understandable that there will be a need to concentrate volume into fewer auctions, this will reinforce the need for a secondary traded market so that participants on both sides can refine their position in between auctions. The best format for this may be an OTC style trading window, as is held currently, but with a minimum frequency of weekly. (this assumes the features of the centralised market are achieved and all parties are capable of trading through the central counterparty on commercially acceptable terms).

Finally, as outlined above, there are methods of calculating the obligation in a fair way that reflects the ability of each generator to provide it, which would inevitability weight the obligation to ESB, as its generation is substantially larger and more diverse than any other. Removal of ring fencing on ESB should not be a condition to imposing an increased obligation that reflects their position in the market, and would be more harmful to future competition in generation and supply than any of the benefits of the solution proposed here and therefore should not be in the scope of this consultation on liquidity.

Market Maker Obligation (MMO)

Options 4 and 5 in the consultation paper explore the possibility of imposing a MMO on a number of parties with a similar set of regulations to that of the S&P obligation placed on the Big Six in GB by Ofgem. Power NI views that there are some positive implications with having market makers in place for I-SEM forward trading; not least the opportunity to trade (almost) continuously in the proposed daily trading windows, and the presence of an observable forward curve in the market. However, the implementation as proposed in the consultation paper has significant drawbacks both for obligated parties who may not be best positioned to manage the risks of the obligation, and for the market as a whole due to the removal of ring fencing on ESB.

A crucial component of the MMO proposal is selection of the market makers, and the proposals in the consultation paper do not follow a clear logic in this selection process. On one hand the paper states, “the SEM Committee is of the view that this type of obligation would be a more proportionate intervention measure if applied to vertically integrated companies”, but yet the selection criteria appear to be solely based on a measure of market share in generation & supply combined as a proxy for financial strength, rather than the true capability of a participant to carry the risk of the obligation. For instance, Power NI remains below the proposed 5% market share threshold but in conceivable circumstances could grow into the scope for MMO. For any party without some balance of supply and generation, and in the extreme case, no supply or generation, there is a cost to carrying the risk of being forced to sell a CfD at its offer price, and then in the context of a rising market, having to buy it back at a higher price, and this will act to distort competition and act as a cost passed through to consumers. The following example from the NERA report[17], shows the dynamics which could result in obligated parties having to take on positions that they would not otherwise want, and how they may incur a loss in trying to close that position out:

[17] NERA Response to the SEM Committee’s Consultation on Liquidity p42 Box 2

Box 2: Example of the Impact of a Market Obligation on a Short Seller

Assume that there are two market participants: Market Maker A (MM-A), who is short, and Market Maker (MM-B), who is long.

At 15:30, MM-A bids of €48.8/MWh with the intention of purchasing 10MW electricity to remedy its shortfall. Because it is an obligated Market Maker, MM-A must also post an offer price no more than 5 per cent above its bid price, in this case €51.3/MWh. Market Maker B quotes offers at the higher price of €53.8, with the intention of selling 10 MW of electricity. Due to regulatory requirement to bid no more than 5 per cent below its offer price, MM-B bids €51.3/MWh. As a result, MM-B instead purchases 10 MW for €513 from MM-A.

At 15:40, MM-A increases its bid price to purchase back from MM-B and increases its offer price to dissuade MM-B from purchasing more. However, MM-B also raises its bid and offer prices and purchases another 10 MW at €51.9/MWh for €519.

Finally, at 15:50, MM-A increases its bid and offer price to €53.4 and €56/MWh in order to close out its position and to ensure that it manages its risks. MM-B increases its bid and offer prices to €50.8 and €53.4/MWh. MM-A finally purchases the 20 MW from MM-B for €1,067. As a result, MM-A loses €35 and MM-B gains €35.

Table 1: A Net Short MM Might Sell at one Price and then Be Forced to Buy Back at a Higher Price

	Time	15:30	15:40	15:50
Market Maker A				
Offer	€/MWh	51.3	51.9	56.0
Bid	€/MWh	48.8	49.5	53.4
Trade	MW	-10.0	-10.0	20.0
Net Position	MW	-10.0	-20.0	0.0
Trade	€	-513	-519	1067
Net Position	€	-513	-1032	35
Market Maker B				
Offer	€/MWh	53.9	54.5	53.4
Bid	€/MWh	51.3	51.9	50.8
Trade	MW	10.0	10.0	-20.0
Net Position	MW	10.0	20.0	0.0
Trade	€	513	519	-1067
Net Position	€	513	1032	-35

If it is reasonable that a standalone supplier or generator could be in scope for MMO, then it is not reasonable to suggest removal of ring fencing on ESB should be in scope for this intervention. Without any changes to ring fencing, ESB and Electric Ireland would individually be Market Maker #1 & #2 according to the RA's criteria and would be capable of providing this service to the market. Given that it is not necessary for the removal of ring fencing, by the scope of an MMO outlined in this paper (and for that matter, any of the other proposed liquidity interventions), any further decisions on ring fencing should be taken outside of this process and subject to a detailed review of its costs and benefits. The review should be similar to that produced in 2010 by CEPA, on behalf of the RAs, which concluded that vertical integration, even with liquidity requirements, would not address the underlying lack of incentive on ESB to offer participants desired products and would place an increased reliance on the RAs to monitor and direct the market.

Furthermore, even in the examples presented where MMO is a better fit for the structure of the market e.g. in GB where the Big Six are of similar magnitude and structure, the liquidity benefits are not clear. In the recent enquiry into the energy market in GB, the CMA found no evidence that MMO had improved overall liquidity[18]. Rather, where S&P had been a benefit had been in giving independent suppliers access to products due to the Supplier Market Access rules; this could be said to be an advantage of any of the proposed interventions, however given that the MMO is an obligation to quote Buy and Sell prices rather than a firm obligation to trade in a product, it potentially has less impact than FCSO where a defined volume will be traded. In summary, it is evident that the benefits of an MMO are unclear particularly in respect of liquidity and hence are not sufficient to justify removal of ring fencing on their own merit.

Other issues with the proposed design are common across all of the proposals; again, the proposal is for a year-ahead obligation, which will inevitably limit any trading beyond this, reducing supplier's ability to hedge, and also removing one justification for the liquidity intervention; a forward curve which aids investment decisions – something which would only be true in the case of a multi-year traded curve.

[18] CMA Final Report paragraphs 89-97

Conclusions

Power NI's recommendation is for an version of the FCSO proposed in Option 2, with the following important adaptations;

- With the correct implementation, the obligations can be calculated in a way that aligns with what a generator could conceivably want to trade forward anyway – this will put a proportionately greater obligation on the ESB portfolio with less variability in their MSQ, without the need to review ring fencing which should be done outside of this process, as the impacts are much wider in scope than liquidity alone.
- The increased obligation suggested in Option 3 can be applied and is still non-discriminatory as ESB's generation market share will be less volatile than other participants across a range of forecast scenarios, hence the obligation is less risky on them.
- Forward curve of up to 2 years, traded in quarters/seasons, secondary market should arise to fine tune these positions at monthly and shape level.
- Generators should be able to discharge their volume obligations over a defined period in the products that they wish to trade.
- RAs need to have clear transparency reporting and stated thresholds at which obligations will/won't apply so generators have the opportunity to trade their obligation in future without need for intervention.

The key benefits of this adapted design are;

- Will give suppliers an opportunity to purchase hedge volumes not being sold currently, hence will be an improvement on the current market.
- Has simplicity in structure that will be easier for all parties to operate in, particularly in the transition period.
- Obligations should be more proportionate in terms of the risks they put on obligated parties and more flexible in terms of how they are fulfilled.
- The centralised trading arrangements should be addressed with the guaranteed trade of FCSO likely to underpin the initial business case for providers.

Hence the RAs would be responsible for;

- Completing a thorough and regular analysis of market forecasts and determining an obligation on each generator (above a de minimis threshold) which is a proportion of their forecast generation across a range of scenarios.
- Set minimum proportions of volume to be traded at different time horizons, e.g. minimum % traded 18 months ahead of delivery, 12 months ahead, 6 months ahead etc.

- Set reserve price for auctions, using existing methodology for DCs i.e. at expected spot price (demand will set any premium over this, still likely to be one as market will remain net short).

Other considerations left to the market;

- Product mix offered to be set by the generators.
- Reserve pricing for any additional volumes offered over obligations to be set by generators.
- Central arrangements to be agreed between the exchange and market participants on commercially acceptable terms that are not a barrier to entry.
- Secondary trading arrangements to be agreed between market participants (and exchange).