



Integrated Single Electricity Market (I-SEM)

**Measures to promote liquidity in the I-SEM
forward market**

Consultation Paper

SEM-16-030

17th June 2016

TABLE OF CONTENTS

1	EXECUTIVE SUMMARY	3
2	INTRODUCTION.....	7
2.1	BACKGROUND OF THIS CONSULTATION.....	7
2.2	OBJECTIVES OF THIS CONSULTATION	8
2.3	WHAT IS LIQUIDITY.....	9
2.4	SCOPE OF THIS CONSULTATION	10
3	IDENTIFYING THE ISSUES IN THE FORWARD MARKET.....	12
3.1	WHAT IS THE PROBLEM WE ARE TRYING TO SOLVE?	12
3.2	INCENTIVES ON MARKET PARTICIPANTS TO PROVIDE LIQUIDITY	13
3.3	EXPERIENCE IN SEM.....	15
3.4	HOW EFFICIENT ARE THE EXISTING FORWARD CONTRACTING MARKETS?	18
3.5	HAS SEM DELIVERED THE EFFICIENT MIX OF FORWARD PRODUCTS?	20
3.6	WILL INCREASES IN LIQUIDITY ARISE ORGANICALLY IN I-SEM?	23
3.7	MARKET EFFICIENCY MEASURES AND PRODUCT AVAILABILITY	26
4	DIRECT CONTRACTS AND RING-FENCING ARRANGEMENTS – IMPLICATIONS FOR FORWARD LIQUIDITY	29
4.1	DIRECTED CONTRACTS.....	29
4.2	RING-FENCING ARRANGEMENTS ON VIRIDIAN AND ESB	32
5	SCOPE FOR INTERVENTION ON I-SEM FORWARD MARKET.....	36
5.1	HOW A REGULATORY INTERVENTION CAN DELIVER LIQUIDITY IN THE FORWARD MARKET	36
5.2	MEASURES TO PROMOTE LIQUIDITY IN THE I-SEM FORWARD MARKET	39
6	REMOVAL OF BARRIERS TO EFFICIENT TRADING	41
6.1	TRADING BARRIERS FOR THE I-SEM FORWARD MARKET.....	41
6.2	POTENTIAL SOLUTIONS.....	42
6.3	TYPE OF TRADING – AUCTION OR CONTINUOUS TRADE.....	44
6.4	PRODUCTS REQUIRED (TIME-OF-DAY, SEASON, MONTH, ETC.).....	45
6.5	VOLUNTARY SERVICE PROVISION POSSIBILITIES	45
7	FORWARD CONTRACT SELL OBLIGATION (FCSO)	48
8	MARKET MAKER OBLIGATION (MMO)	53
9	LIQUIDITY PROMOTION MEASURES – OPTIONS FOR CONSULTATION	65
9.2	OPTION 1: REMOVAL OF TRADING BARRIERS.....	69
9.3	OPTION 2: FORWARD CONTRACT SELL OBLIGATION (FCSO).....	71
9.4	OPTION 3: FCSSO AND REMOVAL OF RING-FENCING ARRANGEMENTS.....	74
9.5	OPTION 4: MARKET MAKER OBLIGATION.....	77
9.6	OPTION 5: MMO PLUS FCSSO	81
10	INITIAL ASSESSMENT OF OPTIONS	84
11	IMPLEMENTATION ISSUES.....	86
11.1	LICENSE CHANGE AND COMPLIANCE MONITORING.....	86
11.2	ROADMAP FOR IMPLEMENTATION INCLUDING TRANSITORY ARRANGEMENTS.....	87
11.3	DESIGN PARAMETERS NOT IN SCOPE OF DECISION	90
12	APPENDIX I - MARKET MAKER, INTERNATIONAL EXPERIENCE	92
12.1	GB MARKET.....	92
12.2	NEW-ZEALAND MARKET.....	95
12.3	NORDIC ID MARKET	98

1 EXECUTIVE SUMMARY

In the high level design for the I-SEM market, it was recognised that there was a need for forward hedging instruments and that liquidity in trading these instruments was an important aspect of a successful market. This consultation focuses on the issue of liquidity in forward markets but also considers the impact of interventions required to address market power. The SEM Committee offers no minded to decisions at this stage.

This consultation paper discusses the issues preventing liquidity in the forward market to grow organically either in the SEM or I-SEM market. It concludes that there are asymmetric incentives to trade between generators and suppliers. This is due to issues related to market structure, share of dispatchable generation and availability of proxy hedges for generators and suppliers. There are also issues related to market maturity. The I-SEM is a new market design and this could also be a deterrent for some market participants to lock in forward positions in the initial period of market operation. In conclusion, there are permanent and transitory issues that should affect liquidity in the I-SEM forward market. The SEM Committee is of the view that these issues should be addressed via regulatory intervention.

Market Power is also an important consideration when designing measures to promote liquidity in the I-SEM forward market. Two market power measures existing in the SEM are revisited for application in the I-SEM. In relation to Direct Contracts, it has been proposed that the volumes of this obligation would be calculated within the same methodology of the current SEM. In relation to price determination, the SEM Committee is consulting upon two different mechanisms. The first would maintain the current methodology of administratively determined prices. The second would deploy a market based mechanism to determine DC prices. In relation to the current ring-fencing arrangements of Viridian and ESB, the SEM Committee is consulting on the possibility of removing ESB's ring-fencing arrangements in the context of some options to increase the provision of hedging products to the market.

In relation to possible intervention in the I-SEM forward market, the SEM Committee is considering measures to either facilitate transactions (via the reduction of transaction costs) or to directly intervening in the market mandating volumes to be traded. Two types intervention are being consulted upon:

- A Forward Contract Sell Obligation (FCSO) on generators to supplement Directed Contracts and volumes sold under the PSO as hedging instruments available to suppliers; and
- A Market Maker Obligation (MMO) on certain larger market participants to promote price discovery and improve market access for all parties.

This consultation then goes on to consider the potential implementation options for any interventions and looks at potential packages of measures that could be applied as follows:

Option 1: Improvements in the trading environment facilitated by improvements in trading platform, market clearing and central credit provision, all of which are being investigated in a separate process; it is considered that this will be of benefit regardless of any other measures taken.

Option 2: A FCSO on generators to ensure more hedging products are available in the market.

Option 3: A FCSO supplemented by removal of ring-fencing on ESB/EI, the latter being traded-off against distribution of continued Directed Contracts being allocated to all supplies except Electric Ireland and enforcing a greater proportion of FCSOs from ESB than from other generators;

Option 4: A MMO on the four largest businesses in the market to provide liquid trading opportunities to the whole market; it is expected that removal of ring-fencing will enhance ESB's ability to provide a market maker service to the market; and

Option 5: A hybrid of options 3 and 4 to both ensure that additional hedging contracts will be provided by generators with a market maker function to facilitate tradability of those (and other) instruments.

For each of these options, details of likely rules and regulatory methodologies are given but, as said, no minded to position has been taken on any of these possible interventions including on whether any intervention is actually required. The exception to this is related to activities designed to encourage improvements in the trading environment as discussed in Option 1.

In all options, some form of Directed Contract will be retained. This means that a certain volume of Directed Contract will be determined by the current basic regulatory methodology; liquidity measures take these into account but are additional to the volumes offered under DCs. Similarly, the arrangements relating to generation sold under terms of the PSO will be retained in the same form as at present.

The tables bellow highlight the building blocks of each option and shows the volumes of hedging that would be available to the market under each package. In relation to the volumes presented, they have been calculated using 2015 data. For the actual obligations, forecast of year-ahead generation should be used.

	Option1	Option 2	Option 3	Option 4	Option 5
Clearing House and Exchange Trading or Tullet Prebon					
Direct contracts	Directed Contracts volumes and prices determined as per current arrangements	Directed Contracts volumes and prices determined as per current arrangements	Directed Contracts volumes determined as per current arrangements sold to non-ESB parties only.	Directed Contracts volumes determined as per current arrangements sold to non-ESB parties only	Directed Contracts volumes determined as per current arrangements sold to non-ESB parties only
Ring-fencing	No Change in the current ring-fencing arrangements of ESB	No Change in the current ring-fencing arrangements of ESB	Integrated ESB GWM and Electric Ireland	Integrated ESB GWM and Electric Ireland	Integrated ESB GWM and Electric Ireland
Forward Contract Obligation	No Forward Contracting Obligation	Forward contract sell obligation on selected generators	Forward contract sell obligation on selected generators	Market Maker Obligation on selected companies (ESB, SSE, Energia and BG Energy)	Market Maker Obligation on selected companies (ESB, SSE, Energia and BG Energy) <i>Plus</i> Forward contract sell obligation on selected generators

	Option 1 TWh	Option 2 TWh	Option 3 TWh	Option 4 TWh	Option 5 TWh
<i>(Non-dispatchable generation)</i>	7.64	7.64	7.64	7.64	7.64
Dispatchable Generation 2015	24.20	24.20	24.20	24.20	24.20
Sources of Hedge					
DCs	3.90	3.90	3.90	3.90	3.90
PSOs	2.48	2.48	2.48	2.48	2.48
FCSO	0.00	10.07	12.99	0.00	6.50
MMO	0.00	0.00	0.00	13.20	6.61
NDCs*	4.80				
Total Hedging Volumes excluding internal hedges and cross border hedges	11.18	16.45	19.37	19.58	19.48
Generation not under externally traded obligation	13.02	7.75	4.83	4.62	4.72
% of disp. gen. under obligation	53%	68%	80%	81%	81%
% of demand covered by FCO	31%	47%	55%	55%	55%

1.1 CONSULTATION RESPONSES

The SEM Committee is seeking specific views from market participants on the following consultation questions:

1. Does the Consultation Paper correctly set out the nature of the problem to be solved? Is it correct that the lack of liquidity characteristic of the SEM will not be satisfactorily rectified through incentives inherent in the I-SEM design?
2. Does the scope of the Consultation Paper set out the full range of potential liquidity promotion measures that should be considered for implementation? If other regulatory interventions are considered appropriate please set out the nature, rationale and parameters of such intervention.
3. Respondents are asked to provide their views on the rationale, parameters and potential effectiveness of each of the regulatory interventions described and explained in the Consultation Paper.
4. What are the important issues to be considered in each of the options? In what way might the options be made more effective? Please set out your views on the rationale for, and value of the parameters employed to determine, the quantity of the obligation in each option.
5. What is the preferred option and why do you consider it preferable?
6. What parameters of the regulatory intervention option should be determined by the Regulatory Authorities and which should be left to market participants to determine?

Responses to this consultation paper should be received by **17:00 on 29 July 2016**. Responses should be sent to Gonzalo Saenz (gsaenz@cer.ie) and Joe Craig (joe.craig@uregni.gov.uk).

Gonzalo Saenz
Commission for Energy Regulation
The Exchange
Belgard Square North
Tallaght
Dublin 24

Joe Craig
Utility Regulator
Queens House
14 Queen Street
Belfast
BT1 6ED

Please note that we intend to publish all responses unless marked confidential. While respondents may wish to identify some aspects of their responses as confidential, we request that non-confidential versions are also provided, or that the confidential information is provided in a separate annex. Please note that both Regulatory Authorities are subject to Freedom of Information legislation.

2 INTRODUCTION

2.1 BACKGROUND OF THIS CONSULTATION

The SEM Committee Decision Paper on the I-SEM High Level Design (HLD) established that the Forward Market in the I-SEM will have only financial trading instruments for within zone trading. This will allow market participants to hedge their exposure to variations in the Day Ahead Market (DAM) price, which is particularly important for independent generators and retail suppliers. The I-SEM HLD acknowledged the importance of long term hedging opportunities for market participants and noted that further measures to promote forward market liquidity may be needed. In February 2015 the Regulatory Authorities (RAs) published a Discussion Paper on Forwards and Liquidity (SEM-15-010) which set out its intention to publish a Consultation and Decision Paper on liquidity within I-SEM and across the interconnection with the GB and wider European market. In December 2015 the RAs published a Decision paper (SEM-15-100) on Financial Transmission Rights, which may be used to hedge prices between I-SEM and the GB market. This Consultation Paper now sets out for consideration by market participants the range of options for improving liquidity in the forward timeframe within the new market.

Lack of liquidity limits the ability of new entrants and small firms to buy and sell electricity in the wholesale market and therefore limits competition in that market. It also limits the ability of existing market participants to increase their share of the market and their scope to provide the best possible deal for consumers. Because poor liquidity is also a barrier to the formation of signals to future prices it also acts as a barrier to investment, which will look to such signals to support its decisions. Poor liquidity is self-reinforcing as market participants need confidence in price signals to trade and adequate volumes traded in order to have confidence that they can find buyers and sellers at acceptable prices. Absence of robust price signals and limited volumes thus deters trading and reinforces a lack of liquidity in the market.

Measures to promote liquidity will therefore facilitate new entry in generation and supply, reduce the ability of any market participant to manipulate the market, increase confidence in prices and thus facilitate trading and investment. The existence of a liquid forward market will allow market participants to reduce price risk. Suppliers facing more volatile wholesale prices will be able to lock in more certain price offers to consumers; similarly generators will be able to reduce uncertainty over wholesale prices by trading forwards. The Consultation paper will review current incentives to trade in the forwards timeframe, how this might be expected to change in I-SEM and options that can be considered to promote liquidity in the new market.

2.2 OBJECTIVES OF THIS CONSULTATION

As noted in the discussion paper from February 2015, the SEM Committee Decision Paper on the I-SEM High Level Design acknowledged the importance of long term hedging opportunities for market participants, particularly independent generators and suppliers, and noted that further measures to promote forward market liquidity may be needed. Responses to that discussion paper generally acknowledged the problem of lack of liquidity in the SEM and a belief that this is likely to continue into I-SEM. Respondents were also agreed on the importance of liquidity in promoting efficient price discovery and trading and allowing parties to hedge exposure to potentially volatile DAM prices in long-term trading; both generation and supply are ultimately long-term businesses with long-term contracts for capacity and fuel as well as for services to customers common in the market; the need for liquidity to flexibly cover these long-term risks is therefore evident for a competitive market and so any expected lack of liquidity may be investigated as a potential market failure warranting intervention.

Therefore, the SEM Committee is considering the following measures to promote liquidity in the I-SEM Forward Market:

- Introduction of Forward Contract Obligation (FCO). This could take the form of a forward selling obligation (FCSO) or a market maker obligation (MMO).
- Establish a path for the introduction of market entities to facilitate forward trading (e.g. Central Forward Trading Platform and Central Clearing Counter Part)

While the trading platform and associated issues will have a big impact on impediments to liquidity in forward markets, the primary focus of this Consultation will be on whether and in what form a FCO should be imposed on the market in order to enhance efficient trading and acceptable risk management in the I-SEM.

This must be viewed within a framework where certain key decisions have been pursued in other workstreams, notably the Market Power workstream. In particular, it has been determined that there will be some form of directed contract to address market power in the I-SEM spot market, which is substantively the same as the current Directed Contracts but with a change in reference price to reflect the replacement of the ex-post pool with the I-SEM DAM. Similarly, the remaining generation for which forward contracts are auctioned under the PSO will continue to be sold in the same manner in the forward market. Therefore, in pursuing liquidity, any measures (if any) will be additional to these. Finally, the SEM Committee has determined that issues of ring-fencing arrangements between certain vertically

integrated generation and supply businesses (ESB and Viridian) should be considered by the Forwards and Liquidity workstream and these are therefore discussed here.

Associated with FCO decisions are issues of delivery mechanism where issues of price transparency, collaterals and availability of liquidity along the forward curve interact with the requirements for a trading platform or visibility within OTC trading. Given the prevalence of voluntary commercially provided forward markets elsewhere in Europe, the issue of seeding a PX or similar mechanism for trading of FCO contracts needs to be considered as a separate topic.

Whereas commercially provided forward markets in Europe tend to be of a continuous trading type, MMOs are contracted by some of these markets' operators to provide a minimum level of liquidity. The need for liquidity is driven from the commercial operators' side by the business model which is primarily based on the earnings from the central counter party/clearing function. MMOs could be applied in any kind of continuously traded market.

2.3 WHAT IS LIQUIDITY

There is no clear definition of liquidity in the academic literature. However, a definition similar to that used by Keynes may be of some value. In this definition, two attributes are required:

- Parties must be able to trade “reasonable” volumes without significantly moving market prices; and
- Parties must be readily able to trade out of positions as well as to acquire those contractual positions.

Neither of these attributes really defines what level of liquidity is adequate, nor defines how liquidity should be measured. In terms of that measurement, the following have been proposed in various academic papers reviewing financial markets¹:

1. Transaction cost measures – these are usually captured in bid-ask spreads;
2. Volume-based measures – large numbers of trades (regardless of size) or else turnover volumes;

¹ For example: *Abdourahmane Sarr and Tonny Lybek: 'Measuring Liquidity in Financial markets'. IMF Working Paper, 2002, <https://www.imf.org/external/pubs/ft/wp/2002/wp02232.pdf>*

3. Price-based measures – smooth change in price should be small in liquid markets because new information is efficiently incorporated and therefore lack of volatility is seen as a measure of liquidity;
4. Other – autoregression (ARMA model) to determine normal volumes as against new information volumes and techniques to remove volatility-induced volatility.

Of these measures, the only practical one to be used to assess policy options prior to I-SEM go live relates to volume-based measures. Therefore, in this consultation, the SEM Committee will concentrate on market churn rates as the main liquidity reference measure.

However, in assessing liquidity, some broader attributes can also be borne in mind:

- **Market depth.** Having a price quoted is insufficient if it is too difficult to access that price. This goes along with:
- **Immediacy.** Access to trading at the quoted price needs to be frequent to allow parties to enter and exit positions easily.
- **Market breadth.** Confidence in a quoted price is necessary, which comes from a variety of traders at similar prices; this should also result in relatively tight bid-ask spreads.
- **Market resilience.** Events will occur that destabilise prices; the speed at which the price of a product returns to market fundamentals is determined by degree of liquidity.

2.4 SCOPE OF THIS CONSULTATION

This document is designed to provide initial thinking on how liquidity will be provided in the I-SEM and how gaps should be filled. To do this several questions will be reviewed:

- What is the experience of liquidity in the SEM:
 - What is the demand for forward liquidity and how do we determine adequacy?
 - What are the incentives to provide forward liquidity?
 - How much liquidity has been provided, how is it provided and is that provision adequate?
 - Have measures to address market power (ring-fencing and Directed Contracts) been successful in addressing shortfall in liquidity and market power mitigation in the forward market?
- What changes in the I-SEM:

- What doesn't substantively change?
- What is the impact of balance responsibility and DAM on risk exposure?
- Requirement for forward liquidity products
- Interaction with market power mitigation measures and CRM
- Delivery mechanisms for voluntary and compulsory liquidity provision:
 - Forward Capacity Sell Obligation (the current Directed Contract mechanism is an example of this, with Non-Directed Contracts as voluntary provision). This raises questions of pricing and volume.
 - Market Maker Obligation (possibly similar to those imposed in GB), which raises issues of volume required and price spread limits
 - Impact of these measures on market power mitigation requirements
 - Impact of ring-fencing changes on these measures
- Trading mechanisms – the trading platform issues of:
 - Collateral requirements
 - Auctioned provision or continuous trading
 - Cleared or uncleared.

These issues are addressed in the succeeding sections of this paper and consultees are invited to comment on both the content and assumptions in this paper. In particular, in Section 9, we set out the options for practical implementation of measures to foster efficiency in forward trading.

3 IDENTIFYING THE ISSUES IN THE FORWARD MARKET

3.1 WHAT IS THE PROBLEM WE ARE TRYING TO SOLVE?

Liquidity in forward energy markets is important for a range of reasons.

Forward hedging is important to suppliers in wholesale energy markets because they effectively sell forward in the retail market at a fixed price (for domestic and SMEs) and look to hedge underlying changes in electricity prices as efficiently as possible. Additionally, volatility in spot market prices, even without underlying changes in average prices, leads to volatility in cashflow, which hedging products can even out. A hedged portfolio is therefore valuable to the supplier.

For generators, there are similar cashflow benefits from hedging their output. In addition to forward sales contracts, other options such as proxy hedges, against fuel price changes, can provide a similar benefit.

Therefore, a shortage of hedging product can make the market less efficient. Liquidity also offers attributes in addition to that of market efficiency, including:

- **Portfolio change.** Acquisition of a hedging product covers an established position but does not allow for evolution of a position over time. A generator may want to get out of a hedged position if price changes move it out of merit or else its set becomes unavailable; a supplier will see changes in its portfolio as customers leave or join a portfolio or if large customers wish to change their consumption profile.
- **Market change.** If market fundamentals change substantially, one side of a hedging contract may find itself exposed to the change in price and may wish to trade out of a position and crystallise its losses before they get larger. It is important for a market participant to be able to adjust its hedging position as the market changes.
- **New entrants.** A large established player may be able to internally hedge but a new entrant can be particularly vulnerable to cashflow instability in the early stages of operation. A new entrant supplier or generator needs to be able to buy into hedged positions; lack of a facility for this could act as a barrier to market entry.
- **Price discovery.** Liquid trading in a product will reveal its true value more effectively than reference to market fundamentals can do. Knowledge of a price curve greatly aids understanding and controlling risk.
- **Tradability.** If a party has confidence that it can exit a position, it will have confidence to trade in a hedging product in the first place. In this aspect, liquidity promotes trading and therefore creates a virtuous cycle.

Liquidity – the ability to sell as well as buy into a product without unduly moving prices – is therefore a necessary component of efficient price formation and trading.

There are many reasons why parties will want to provide or might want hedging products. This will depend on the party's individual circumstances. To transact a hedging product, the party does not need to be a market participant. This is especially so where the market is financial rather than physical, which is the case for forward markets in the SEM and will also be the case in I-SEM.

An ongoing desire among market participants, as already stated, is to manage their exposure to market price volatility. The SEM operates as an ex-post pool, trading at short-run marginal cost (SRMC). Although this is, in many cases, predictable and will be driven largely by daily load profiles, variations in weather variables, conventional generator availability and intermittent generation variability can all serve to create price spikes and general price uncertainty. All parties in the market have an incentive to trade in CfD products that even out this price volatility in order to create a revenue or cost stream that has a more predictable cashflow. One obvious way to hedge against this cashflow volatility is vertical integration – when prices are above average, the generation business will make extra revenue to match the corresponding losses of the supply business, and vice versa. A CfD contract mimics vertical integration.

However, the ability to lock in a price against movements in underlying prices is valuable to both buyers and sellers. Within this parties have different motivations and risks to cover depending on their main business activity. Again, vertical integration provides a natural hedge against underlying price movements, and a CfD mimics this hedge.

3.2 INCENTIVES ON MARKET PARTICIPANTS TO PROVIDE LIQUIDITY

In order to understand changes in underlying prices in the cost-based SEM pool, it is necessary to understand which generators will be contesting to set the marginal price at different times of the day (or season). In fact, for much of the load curve, the price will be mainly set by gas plants; on occasion, coal plants will set the price but imported coal prices are linked in the medium term to international gas prices and so the predominant long-term effect on prices will be the cost of gas. As a readily tradable commodity, even where gas is purchased under long-term contract, there will be a tendency for prices to be marked to market and so underlying price movements will have an effect on the pool price. As was seen with respect to pricing of DC contracts, this tends to hold well as long as forward gas prices reasonably

reflect spot market outcomes². Against this background, different parties will place different valuations on forward hedging:

- **Suppliers.** The supplier trades only in electricity, which is sold forward to customers at a partly sticky price. The need to lock in a forward electricity price is therefore strong. A supplier will even pay a premium to cover against price increases in the underlying spot price because such price increases will not be easily recoverable from customers. Suppliers are reluctant to provide hedging to the market but, in principle, could offer services based on their cashflow.
- **Gas-fired generators.** To the extent that spot electricity prices reflect spot gas prices, which will be the substantial position in a cost-based pool, the main hedge that the generator requires is a gas-price hedge covering longer-term gas prices. This does not eliminate the need for electricity price hedging but it reduces the need for it and suggests that no premium should be required.
- **Coal-fired generators.** As noted, coal prices are partly correlated with gas prices but this is far from perfect. It is also more difficult to find a coal price hedge in the market. For this reason, there may be benefit in an electricity price hedge. However, the incentives are weak.
- **Wind farms.** Most wind farms have some form of price support. Currently, the Northern Ireland scheme is based on NIROCs, which pay separately for energy and for green benefit. Therefore, for the energy portion, NI renewables generators should be interested in electricity price hedges to lock in a stable price although, in reality, only a multi-year hedge that covers off financing costs would offer significant benefits. In the Ireland, generators under the REFIT scheme will effectively have a CfD with an ex post volume denominator that will set a strike price based on the target price for REFIT and so are indifferent to the actual pool price.
- **Other generators.** There is an assortment of technologies for both peaking and baseload dispatch including several generators with must-run status. The must run generators will be interested in electricity price hedging because they are essentially price takers who will want to lock in prices to even out

² Looking back to **Error! Reference source not found.**, it can be seen that forward prices did not reflect the collapse in spot gas prices in 2009, which is why the strike price of DC contracts spiked relative to pool outcomes in that year; this is a detail that does not really challenge the underlying proposition related to the usefulness of forward hedging.

cash flow. Peaking plants have less interest in hedging against pool prices as they will not be dispatched in most hours anyway.

- **Interconnector traders and non-physical traders.** The hedging needs of interconnector traders are complex because they have positions in both the GB and Irish market. In many cases, they may take their primary hedging position in the GB market, which has established forward trading in a more liquid market. The position for them will substantially change under I-SEM because FTRs will be on offer. Non-physical traders will not use CfDs for hedging because they will not have a physical position to take and so will not be exposed to the pool reference price. In reality, such traders have not been a feature of the SEM market other than incidentally through physical positions on interconnectors.

For generators other than those supported by REFIT, offering a forward hedge involves dispatch risk. This is because, if not scheduled in the pool, they must still pay out based on the CfD strike price but will not have offsetting revenue from physical dispatch. This point should not be exaggerated because the payout will relate to the difference between the pool price and the strike price in the CfD (and might actually offer some revenue) whereas failure to be dispatched in the pool simply means that the generator loses dispatch revenue but saves on variable costs. Nevertheless, dispatch risk means that portfolio generators may be in a better position to offer forward hedging than would standalone generators.

Although greater price volatility can be expected in the DAM than in the current pool, the underlying incentives will tend to be the same.

3.3 EXPERIENCE IN SEM

Recent evidence from SEM highlights the shortage of hedging products that have been available for suppliers. There has also been a lack of secondary trading of these products.

Supplier	GWh per year	Percent of total
Electric Ireland	12,417	38%
SSE Airtricity	7,229	22%
Energia	4,662	14%
Power NI	2,823	9%
Bord Gáis Energy	2,626	8%
LCC/Go Power	1,078	3%
Others	1,051	3%
Budget Energy	222	1%
Vayu	392	1%
PrePayPower	386	1%
Firmus	20	0%
Total	32,908	100%

Table 1: Potential demand for hedging products by supply company

Focusing on 2015 data, Table 1 shows the amount of system load of suppliers that they would seek to hedge.

With regard to the volume of generation available to hedge, Table 2 below shows the Market Scheduled Quantities for 2015 that was provided by dispatchable generation plants, which could be best placed to offer forward hedges. This results in a total MSQ of about 24.2 TWh as against demand of approximately 33 TWh, from Table 1 above. In this analysis, hydro and wind farms are excluded (6.8 TWh), as is the MSQ of interconnector volumes (3.8 TWh)³.

	MSQ 2015 (TWh)	Share
ESB	14.62	60.4%
Bord Gais	2.59	10.7%
AES	1.68	7.0%
Aughinish	1.34	5.5%
Tynagh	1.26	5.2%
SSE	1.22	5.0%
Bord na Mona	0.81	3.4%
PPB	0.31	1.3%
Energia	0.17	0.7%
Others	0.15	0.6%
DSU	0.04	0.2%
First Electric Ltd	-	0.0%
Grand Total	24.20	100%

Table 2: Dispatchable MSQ by Market Participant in 2015

From the figures above, it can be seen that there is a mismatch between demand and potential suppliers of hedging products. Figure 1 illustrates this asymmetry.

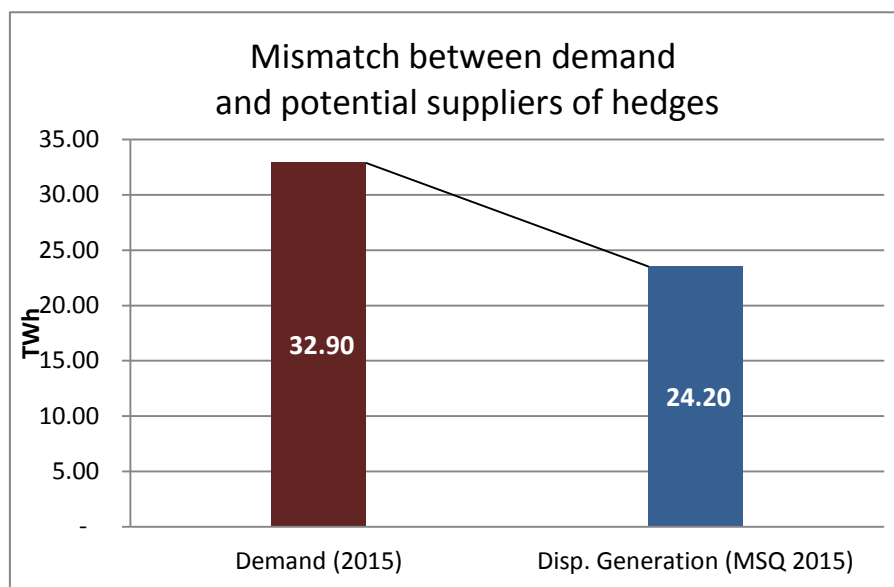


Figure 1 Comparison of demand and dispatchable generation, 2015

³ Contracts traded across interconnectors do act as a source of forward hedging also.

Table 3 shows the extent of direct hedges provided in the SEM for the year 2015:

- Within zone energy contracts accounted for approximately 34% of the market.
- Transactions across the interconnector, accounted for a further 11%. Market participants are able to use trades across the interconnector (by entering into a forward contract in GB and buying a transmission right to access the SEM) to hedge their price exposure in SEM.
- In addition to external hedges, some retail suppliers are internally hedged with own generation. The extent of internal hedging reduces the need to contract with third parties to hedge exposure to spot price fluctuations. This “natural” hedge is estimated to be 26.5% of the market.

The combination of internal and external hedging means that approximately 71.5% of the total market is hedged against spot price fluctuations.

	Volumes of 2015 in TWh	Share of MSQ
CfDs	11.21	34.1%
Interconnectors	3.82	11.6%
Internal Hedges	8.73	26.5%
Total	23.76	71.5%

Table 3: Hedging in SEM for 2015

Table 4 breaks down the number of CfDs sold in SEM for 2015 into DCs, PSO and NDCs.

	CfDs 2015 in TWh	Share of MSQ
DCs	3.92	11.9%
PSO	2.48	7.5%
NDCs	4.80	14.6%
Total CfDs	11.21	34.1%

Table 4: Breakdown of CfDs in the market by type, 2015

Table 5 show the extent of internal hedging in SEM based on MSQ for 2015:

	Volumes of 2015 in TWh	Share of MSQ
ESB ⁴	4.38	13%
SSE ⁵	1.61	5%
BGE	2.59	8%
Energia	0.15	0.5%
Total Internal Hedges	8.73	26.5%

Table 5: Breakdown of internal hedges by company, 2015

⁴ This refers to the legacy contracts between the Synergen and Coolkeeragh plants and ESBIE (now part of Electric Ireland), which was examined in SEM-12-002.

⁵ This figure has been adjusted to reflect Great Island CCGT operating for 12 months.

The overall level of historical hedging is lower than that experienced in other similarly operated competitive markets⁶.

In their responses to the Forwards & Liquidity Discussion Paper (SEM-15-010) published on the 10th February 2015, several market participants indicated that the above level of hedging would not be sufficient to satisfy the needs of suppliers. Among these responses was a general recognition of the low level of forward liquidity and concerns that the challenges posed by small market size, scheduling risk, growth of variable generation and market concentration were to remain in I-SEM.

Suppliers also use proxy hedges to hedge exposure to spot price fluctuations – via hedges against the GB gas spot price, plus the carbon price. The SEMC does not have information on the magnitude of such hedges held by market participants in the SEM, but recognises that they are unlikely to be as efficient a hedge for a supplier as an energy contract priced against the spot price.

3.4 HOW EFFICIENT ARE THE EXISTING FORWARD CONTRACTING MARKETS?

Directed Contracts

The amount of Directed Contracts sold is the volume in excess of a particular benchmark determined so that SEM spot market concentration is reduced below a certain HHI (Herfindahl-Hirschman Index) threshold. The HHI index measures concentration in an industry and is equal to the sum of the squares of the market shares of firms in the industry. The current HHI threshold set by the SEM Committee is 1,150.

In 2015, the volumes of DCs sold by ESB were 3.9 TWh representing 11% of annual market throughput (i.e. of generator MSQ). Volumes of Directed Contracts are determined by modelling future market outcomes including the SMP, market concentration and the forecast market share of ESB generation, and an econometric pricing model to determine the price at which Directed Contracts will be allocated. Using the modelling assumptions set out in section 6 of the Market Power Consultation Paper (SEM-15-094) the volume of DCs allocated would be 4.118 TWh in 2019 and 2.764 TWh in 2024.

The price of Directed Contracts is set using a clean spark spread formula to simulate the forward price of electricity in the SEM; currently therefore the critical variables are the European carbon price and the forward price of gas.

⁶ In the days of the England and Wales pool, hedging levels of 80%-90% were normal.

Figure 2 is derived from the SEM Contracting Report, 2007-2013⁷. It shows that the NRAs have been progressively more accurate at forecasting a consistent clean spark spread and that between 2011 and 2013, the strike prices of CfDs were very close to the outturn SEM pool results (i.e. an average zero payout when the CfD was settled).

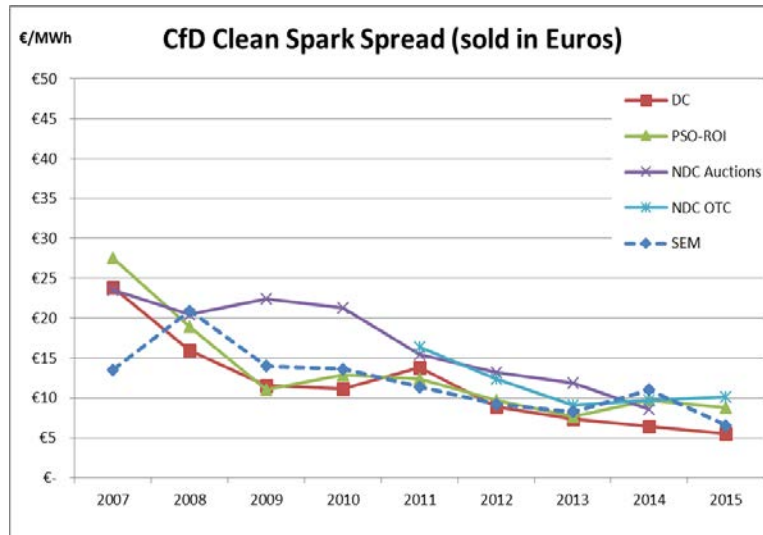


Figure 2.1: Results of calculated prices for Directed Contracts

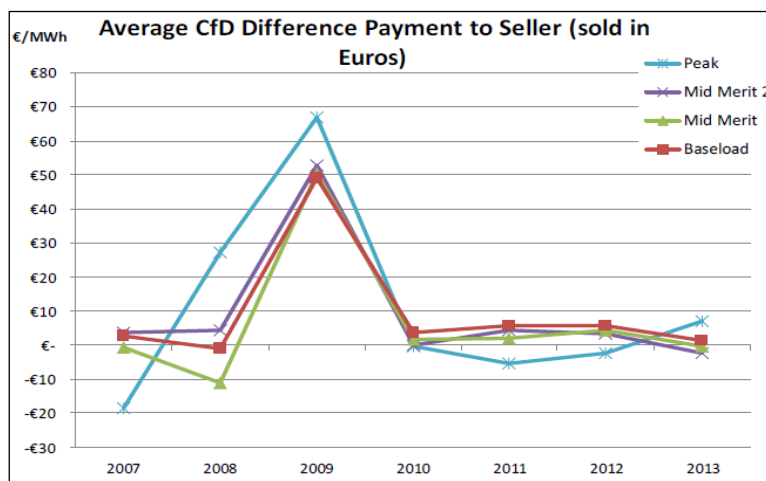


Figure 2.2: Results of calculated prices for Directed Contracts

DCs are sold in quarterly tranches, with a part of the allocation for any quarter being sold in quarterly allocations, as well as into different time-of-day allocations to cover peaking and mid-merit as well as baseload.

⁷ <https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-14-073%20SEM%20Contracting%20Report%202007-2013%20SEMC.pdf>

Non Directed Contracts

ESB and other generators offer non-Directed Contracts (NDCs) at periodic auctions or OTC. Some of the auctions relate to Public Service Obligations (PSO) but the contract price is fixed by the auction rather than being administratively set. Although the PSO auction revenues do not go directly to the seller, as they are used to offset consumer levies to pay for the PSO, for the buyer, they are the same as any other hedging contract.

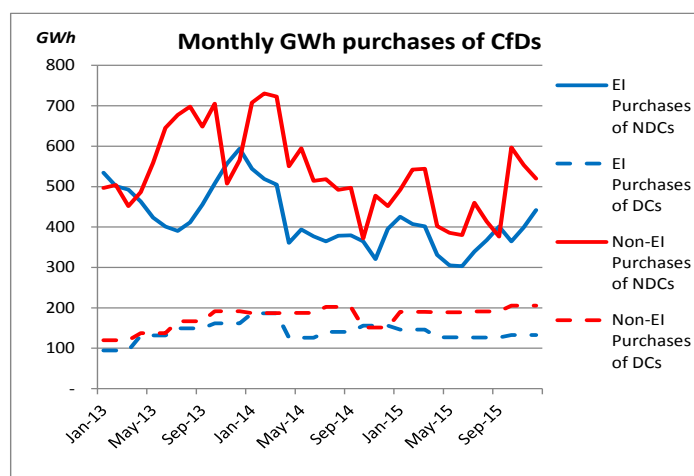


Figure 3: Volumes and prices of DCs and NDCs, 2013-2015

In Figure 4 we track the volumes of contracts sold in the forward markets. In the figure for GWh purchased, the purchases of NDCs are displayed as additions to purchases of DCs; this is essentially for display purposes. These show that DCs represent a minority of the market. This is further stressed because these figures exclude volumes sold for which no specific buyer has been identified; these volumes represent an additional 9-10% of volumes. It should also be noted that quarterly contract volumes and costs have been pro-rated across the months of the quarter and that contracts sold in GB£ have been converted into Euros at the prevailing exchange rate. In January 2013, ESB ceased selling most NDC contracts at auction and instead offered the volumes on a bilateral OTC basis; it is not known what impact this may have had on volumes and liquidity. Rather than increasing, the charts indicate that there has been a decline in sales of NDC hedging products in 2015.

3.5 HAS SEM DELIVERED THE EFFICIENT MIX OF FORWARD PRODUCTS?

DCs are approximately 1/3 of the overall forward market volume. They are allocated to suppliers as baseload, mid merit and peaking. Obviously, the volumes of peaking product will be less due to the limited hours that they cover. However, even taking this into account, there are many periods when suppliers have not taken up their allocation of peaking products and, sometimes, mid-merit allocations are similarly not taken up.

Figure 5 amalgamates DC and NDC volumes; in the dataset used, those products without an identified buyer have been excluded. The figure shows the dominance of baseload products; it indicates a declining trend in uptake of non-baseload products, with only mid merit retaining any significant volume. Although this may be due to the relative prices of products, it does mirror European experience where forward markets are dominated by baseload products in most countries. Looking at the prices in the figure, apart from a spike in February 2015 for the mid merit 2 product, the prices do not look anomalous although a question arises why the prices of mid merit 2 had fallen below those of mid merit by mid-2015.

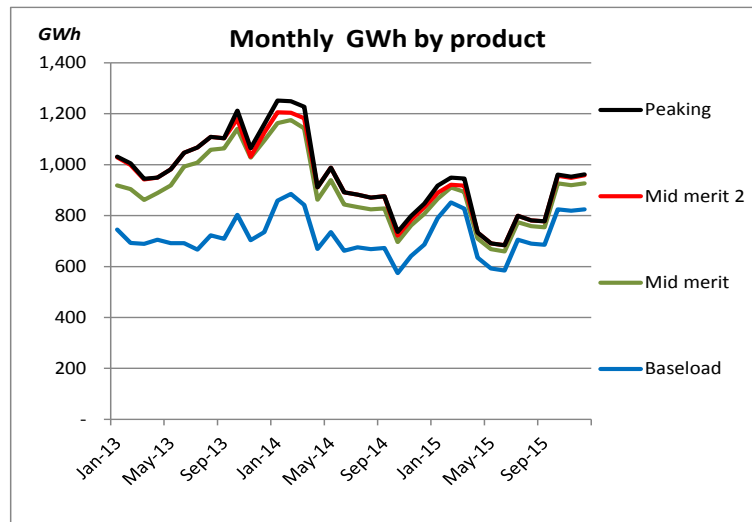


Figure 5.1: Volumes of Product types sold, 2013-2015

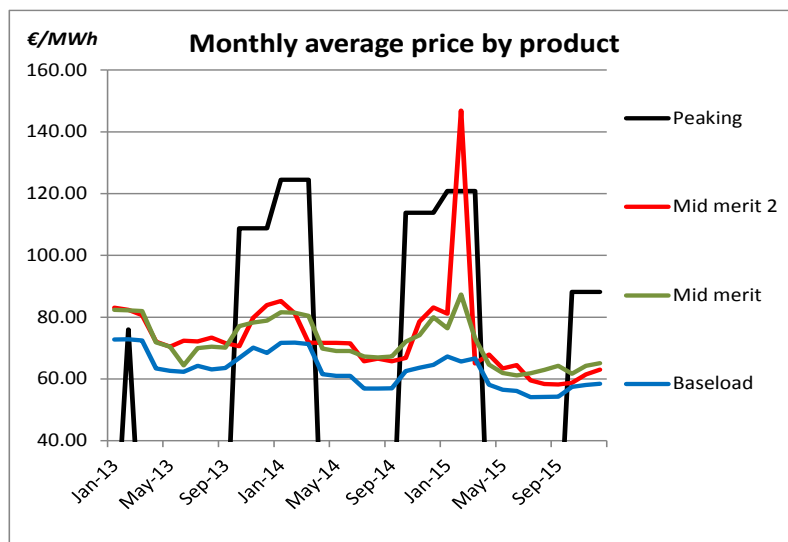


Figure 4.2: Prices of product types sold, 2013-2015

Figure 6 looks at the products available in the market. Including DCs possibly increases the relative volume of quarterly products but, were there a preference in the market for shorter-duration products, it would be expected that this would be compensated for by a predominance of monthly NDCs, which would seem not to be

the case. Again, this is not atypical of European experience where longer-duration products tend to be preferred.

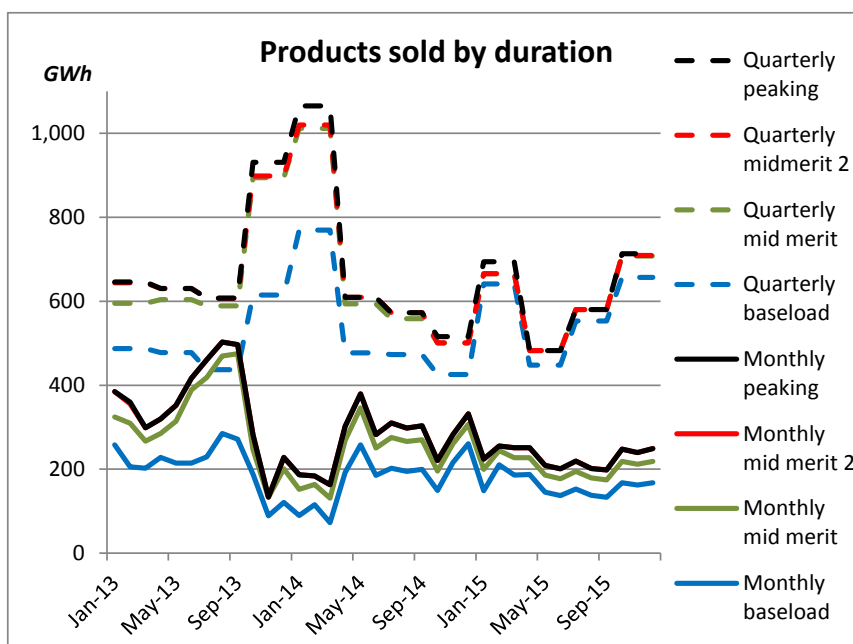


Figure 5: Volumes of products bought by duration, 2013-2015

Putting these volumes in perspective, products sold for delivery in a month would have differing actual volume requirements. Assuming there are 3 products in the market: baseload, mid merit (mid merit + mid merit 2) and peaking and assuming the product size is 1 MW for delivery across the year for each auction (or OTC sale) then the calculation from the following table applies:

	Sale per auction (MW)	Auctions per year	Hours per week	Hours per day	Hours per year	MWh per MW sold per year	Market* take-up (GWh)	MW traded per quarter
Base load	1	4	168	24	8,760	35,040	8,830	252
Mid merit	1	4	70	10	3,650	14,600	1,228	84
Peaking	1	4	20	2.86	1,043	4,171	97	23

* All DCs and NDCs sold in 2015 for whom a buyer is known

Table 6: Calculation of delivery commitment per MW of product offered

The calculation in the table needs a bit of explanation. Selling 1 MW for delivery across the year would mean that the MW would be delivered in every hour for which the contract is valid. Mid merit and Peaking contracts are only available for certain hours on weekdays, whereas baseload is delivered 24/7; it is necessary to calculate an average daily delivery in order to work out total delivery of 1 MW across the year. If there are 4 auctions in the year (rolling quarterly delivery) then the MWh per MW sold per year will be 4 * hours of delivery per year. Market take-up is actual sales

recorded for delivery in 2015. In the final column, dividing Market take-up by MWh sold in the year will give number of MW sold across the market for each product in each auction. In fact, the situation is much more complex with not all products being sold for each month, and with monthly sales (mainly OTC) also occurring. Nevertheless, it indicates that the ratio of products used in the market is something like 12/4/1 for baseload/mid merit/peaking.

This calculation is provided to give an idea of both scale and market demand for product at auction, which provides scope for potential regulatory interventions discussed in this consultation.

3.6 WILL INCREASES IN LIQUIDITY ARISE ORGANICALLY IN I-SEM?

Expected pricing in the DAM and incentives to hedge

Under I-SEM, the main change for the forward market will be that the reference price is likely to come from the Day Ahead Market (DAM), rather than from the ex-post pool. It is conceivable that a reference price could come from the intraday market or even the balancing market (both of which would suit wind generators whose forecasts at the day ahead stage are not particularly accurate) but, given that the reference price for FTRs and for other European markets will be the DAM clearing price, and it will be the most liquid spot market, this is the most appropriate reference price for forward contract settlement.

The DAM differs from the pool in several ways:

- It is a voluntary market in which buy and sell volumes are freely priced by generators and suppliers. In particular, unlike in a cost-based pool, generators will need to work out how and when they might recover non-energy costs such as start-up and de-synching costs, which will no longer be optimised by a pool algorithm.
- There will be a more direct influence from prices in the GB market because the EUPHEMIA algorithm will seek to optimise flows between the markets through market coupling with prices expected to converge more than they do at present.
- The balance position of parties in the market is essentially a commercial decision and not mandated by TSO forecast of the clearing volume.
- Energy produced, which is not sold in the DAM will be available for intraday (IDM) and balancing (BM). This means that price expectations in these markets will influence prices parties are willing to accept in the DAM.

The implications of this are that the DAM price could be more volatile than the current pool price, particularly in the early stages of the market. This increases the

incentives on generators to seek forward hedging instruments. Although the underlying incentives listed in Section 3.2 will still apply, all but renewable generators with a support scheme based on REFIT will have an increased incentive to hedge forward.

Additional Hedging Sources for I-SEM

By 2020, the PSO contracts that ESB currently administers will have stopped. The volumes from plants such as Aughinish, Tynagh and Edenderry have already declined to zero, while the PSO support for the remaining peat plants will expire by the end of 2020. However, after the expiration of the PSO contracts these same plants will have an incentive to offer un-regulated forward contracts as a mechanism to hedge their own exposure to spot price volatility, to the extent they remain operating in the market. This could result in an increase of hedgeable generation to be offered in the forward market, other than via the PSO CfDs.

Role of GB market and FTR in providing liquidity

Under I-SEM, FTRs will provide access to GB futures. In terms of forward hedging, a CfD in I-SEM is assumed to be equivalent to an FTR plus a CfD in the GB forward market. In order to trade in the GB forward market, the trader will need to take a physical position in that market or else trade with somebody who can give him such a position. This should not prove a major obstacle because the GB market will still give the necessary requirement: a forward strike price for the trade, referenced against a day ahead price that will be the same price against which FTRs are referenced on the GB side.

FTRs will therefore contribute to the I-SEM forward market liquidity. How much it contributes will depend on liquidity in both the FTR forward market and the GB forward market. It will also rely on the capacity of the interconnection with GB through the Moyle and East West Interconnector to back sale of FTRs. These have a maximum capacity of 500MW each. Moyle may be subject to restrictions on maximum export capacity to GB from 2017. However at this stage it has not been defined how these physical restrictions will affect the provision of FTRs. Discussions are ongoing between Mutual Energy, National Grid, Scotch Power, Ofgem and UR to determine a compensation scheme for the periods when Moyle's capacity to export is reduced due to transmission constraints in the Scotch side. For that reason the assumption is that FTRs would be sold based on Moyle's full capacity (500 MW).

Assuming GB forward market liquidity is not constraining, FTRs would contribute the following to the I-SEM forward market liquidity:

FTR churn rate * {Sum(ICs, direction) average directional hourly available FTR capacity } *8760

With FTR capacity = (1 - loss factor) * IC capacity, as the hedging capability per unit of FTR will be reduced by the loss factor.

Assuming a maximum available capacity of 500 MW on Moyle and 500 MW on EWIC, loss factor of 1.8% on Moyle and 5% on EWIC, FTRs could contribute to forward liquidity and cover supplier's hedging demand for as much as:

$$8760 * (500*0.95+500*0.982) = 6.34 \text{ TWh}$$

Forward contracting obligations derived from supplier's hedging demand will therefore take this into account.

Wind farms and forward liquidity

Wind generation accounted for approximately 20% of the MSQ in 2015. In Ireland, generators under the REFIT scheme will effectively have a CfD with an ex post volume denominator that will set a strike price based on the target price for REFIT and so are indifferent to the actual pool price. Hence, they have no incentive to offer contracts or any need to hedge.

Given the intermittent nature of wind output, it is not a natural technology for backing off sales of forward contracts. However, given the pivotal role that wind output can have in setting prices in the day ahead market (windy days cause prices to drop while windless days could lead to potential price premiums in the DAM) it is worth exploring any role that wind might have in provision of forward CfDs to the market.

If a wind farm bought a CfD then on windy days, it could pay out because the DAM price would be low, but it would receive revenue out of REFIT because it is paid when generating; on a windless day when the price was consequently high, it can expect to receive money on the CfD, which would partly offset revenue that was not coming in due to lack of delivered energy. A wind farm could therefore use CfDs to partly hedge its cashflows out of the physical market. This increases demand for hedging rather than increasing supply of hedging products.

Of course, in hedging against DAM prices, the wind farm is creating a potential exposure to the imbalance price because, between DAM closure and real time, the wind farm has a risk of error in its day ahead forecast (perhaps, on average, 10%) meaning that there is a 10% chance that the hedge bought in the forward market to support cashflow, would turn out to reinforce imbalance costs (the forecast windless day turns out to be windy so that the cashflow consists of a payment for the 'small'

difference between the REFIT and the DAM price plus a lowish payment for the spill energy in the balancing market less a payout on the CfD due to the high DAM price; or the windy day turns out windless so that cashflow consists a 'large' payment for the difference between REFIT price and the low DAM price offset by a large imbalance payment – the CfD pays out for the difference between the low DAM price and the CfD strike price). In fact, the CfD is largely compensating the wind farm for the risks inherent in trading physical in the DAM but does not compensate much for actual forecast error, which is a within day problem.

The Aggregator of Last Resort (AOLR) or any other wind farm aggregator may be more likely than an individual wind farm to trade forward but would most likely apply the same logic as the individual wind farm as described above: i.e. as a buyer of forward hedging products to even out cashflow variations caused by the variability of the day ahead forecast of wind availability, and relying on portfolio diversity effects to minimise imbalance due to errors in that forecast.

All in all, the increase in wind penetration in the generation mix is likely to increase the demand for hedging products rather than the supply.

3.7 MARKET EFFICIENCY MEASURES AND PRODUCT AVAILABILITY

The potential services that could be provided to promote market efficiency are discussed in more detail in Section 6 of this consultation. It is generally agreed that a major obstacle to trading is the absence of a multilateral framework for credit cover and collateral provision. In GB, a General Trading Master Agreement (GTMA) has been in operation for many years. This has helped to reduce the legal costs in setting up general credit arrangements for bilateral trading but has not reduced the need to arrange additional credit and collateral terms. This is one of many reasons why barriers to entry in GB were considered too high and resulted in Ofgem intervention. Another development in GB has been the more recent establishment of forward markets but these have only more recently gained traction.

However, the I-SEM market will remain fundamentally different to the GB market in that it is only a physical market from the day ahead stage onward, and before that it will be purely financial.

In this context, the key problems remain two linked issues:

- Agreement on collaterals and transaction costs of trading
- Cost of provision of collaterals.

Recent developments in European financial regulation seem likely to increase barriers to small players because larger players will be reluctant to increase trading

that may cause them to be treated as financial service providers with onerous reporting and margining requirements. Therefore, the need for a centralised market seems to be greater than ever. As Section 6 discusses, SEMC are considering various options to encourage such centralised provision. Among the most pressing needs are:

- A trading platform, offering visibility of prices and volumes;
- A central clearing provider (CCP) providing assurance of payments on trades;
- A central collateral provider that provides access to credit terms and to trading with the CCP for small parties.

It should be noted that none of these elements will necessarily reduce the cost of collaterals to parties, but they could allow netting of credit positions, reducing net collaterals that have to be provided, and could also allow cross-market collateralisation allowing positions from different timeframes (and different markets such as forward CfDs and FTRs) to be netted off, further reducing collateral requirements.

As noted, while more efficient trading arrangements will improve access to the forward markets, it seems likely that this will not on its own sufficiently increase the volume of hedging product to meet market requirements.

There also remains a trade-off between the limited volume of product available for trading and the frequency of trading. Concentrating trading into defined auctions will improve throughput in those auctions, which will improve the reliability of the prices achieved, and reducing the number of products available will have a similar effect. However, this will not necessarily be sufficient for true liquidity if the holders of forward hedging instruments cannot match products sufficiently to their portfolios and cannot trade out of hedged positions as circumstances change. This requires an arrangement whereby a variety of different products are available and that a continuous price is available at which trades can be conducted.

The low level of liquidity in the SEM and the extent of the problem to be addressed can be demonstrated in the figure below which shows the level of churn in European markets, that is the degree to which forward products are traded and re-traded. This illustrates the relatively low level of liquidity in the SEM in comparison with other European markets.

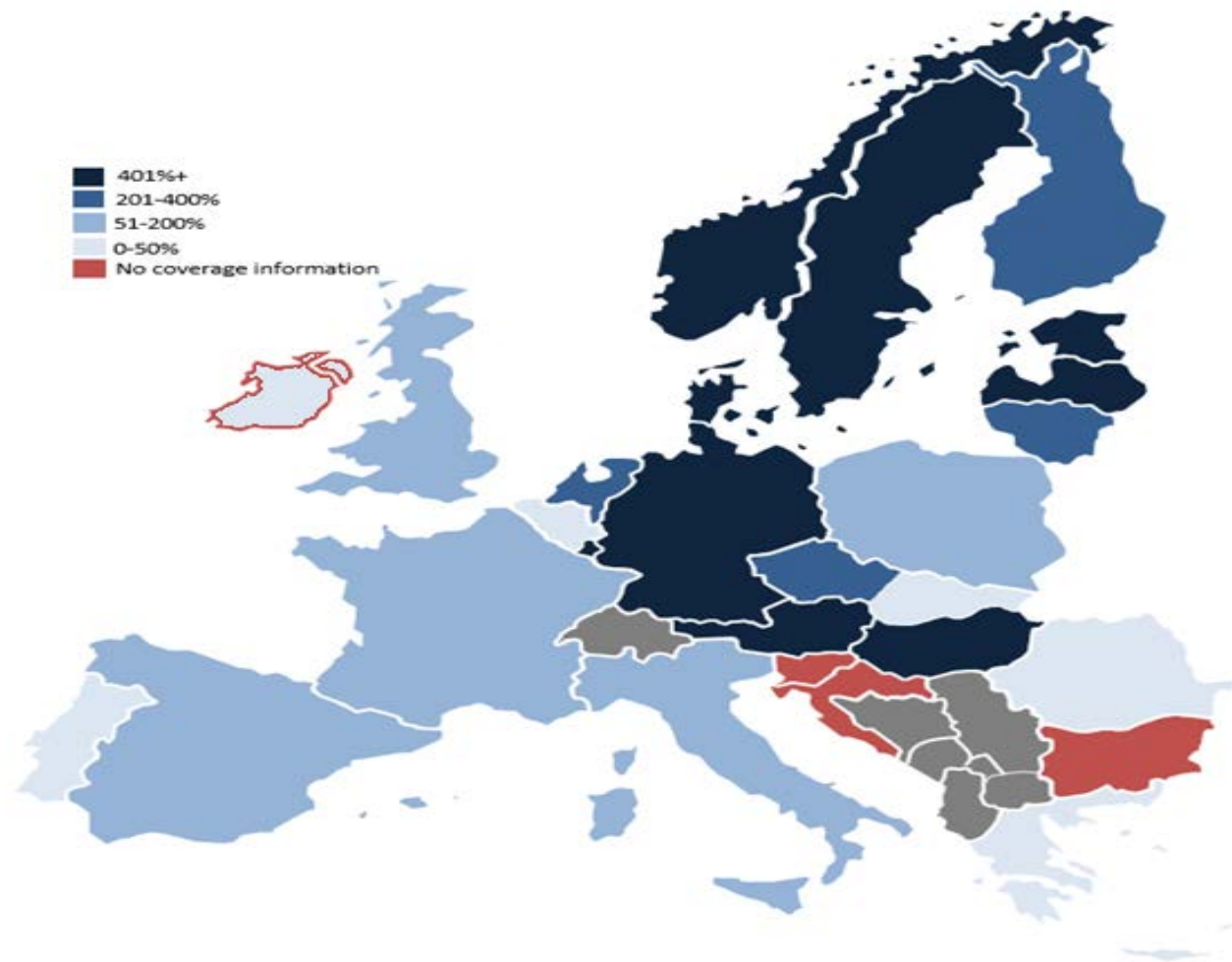


Figure 6: Levels of liquidity in European Markets

4 DIRECT CONTRACTS AND RING-FENCING ARRANGEMENTS – IMPLICATIONS FOR FORWARD LIQUIDITY

4.1 DIRECTED CONTRACTS

The Market Power Decision Paper determined that there would be a Forward Contracting Obligation (FCO) in I-SEM that would be implemented in order to address market power in the spot market. In the SEM, there is an obligation on ESB and PPB to sell Directed Contracts at a price and volume determined by the Regulatory Authorities.

The Market Power Decision Paper (SEM-16-024⁸) also determined that the quantification, price form and allocation of the FCO would be determined in conjunction with the policy options to promote overall forward liquidity, which would allow the character of the contracting obligation to be considered holistically, taking account not only of its effects on spot market power mitigation but also on liquidity. Two potential designs of this Forward Contracting Obligation are possible that address market power and liquidity concerns and are presented in this section.

- The current approach to Directed Contracts could continue but with a necessary change to reflect the replacement of the ex-post pool with the Day Ahead Market as the reference price.
- The second approach would differ in that the price of the Directed Contracts would not be set by the RAs but would be determined by auction of market participants with a reserve (minimum) price set by the Regulatory Authorities.

Both approaches are designed to address concerns about market power in the I-SEM Spot Market.

1. Allocation of Directed Contracts – current methodology

The rationale for the current methodology is reduction in spot market power achieved by mandating the largest generator (and others potentially) to sell forward CfDs representing the volume of generation sales in excess of a certain threshold. Selling CfDs forward addresses concern about competition in the spot market because it mitigates the incentive on the largest generator(s) to ramp up spot prices because it would simply compensate for any price increase through payment on the CfD.

⁸ <https://www.semcommittee.com/publication/sem-16-024-i-sem-market-power-decision-paper>

For market participants purchasing the CfDs, these contracts offer hedging against changes in the underlying spot price and against spot price volatility, both of which are valuable to their business. The buyer of the CfD is assured of paying the strike price of the CfD for the designated volume of energy, regardless of the reference price (market price) and similarly, the seller is assured of receiving the strike price in the same circumstances. In the SEM market, the reference price is the System Marginal Price (SMP) derived from pool settlement and in the I-SEM it is proposed this will be the clearing price from the Day Ahead Market. However it is the ability to subsequently buy and sell these CfDs at reasonable prices that will determine the market's valuation of the CfD and its contribution to market liquidity.

Currently, Directed Contracts volumes are calculated to reflect a virtual restructuring of the market so that market concentration is reduced below a certain HHI (Herfindahl-Hirschman Index) threshold. The HHI index measures concentration in an industry and is equal to the sum of the squares of the market shares of firms in the industry. The maximum value for HHI in an industry in which a single firm has 100 percent of the market is therefore 10,000. The market share calculations that underlie the HHI analysis are based on the capacity that is relevant to competition, calculated hourly for the various generation owners based on the cost of each generation owner's units. In a given hour a unit's capacity is considered potentially competitive so long as its cost is less than or equal to $SMP * (1.05)$. Units that have no incentive to raise the market price are treated as fully competitive supply in the HHI calculation. The current HHI threshold set by the SEM Committee is 1,150.

DCs are sold in quarterly tranches, with a part of the allocation for any quarter being sold in quarterly allocations, as well as into different time-of-day allocations to cover peaking and mid-merit as well as baseload. Forward Contracting Obligations based on the current Directed Contract methodology may be amended in their allocation if ring-fencing is removed from ESB so that these contract volumes are allocated only to third parties (This is discussed in Section 9).

The advantage of the current methodology is that it clearly addresses market power concerns, reducing the uncontracted volume of ESB generation to a competitive level, and reduces the incentive on ESB to submit non-competitive prices into the spot market as the forward contract already sets the price received for the volumes sold. This price is calculated directly by the RAs and places the onus on the RAs to accurately price the SMP either in the current pool or DAM in I-SEM.

It is to be anticipated that the price in the DAM will be more uncertain and more volatile and it may therefore be possible that the RA determined price will less accurately reflect actual DAM prices, which may be to the benefit of the provider or buyer of the CfD. To the extent that this leads to trading in the Directed Contracts,

reflecting differing views of the value of the Directed Contracts, this will aid liquidity although the potential for this will be dampened by the lack of forward hedging premium within the price. To the extent that the RAs' determined price reflects the experience of the SEM, the Directed Contracts will not be subject to resell and purchase and will not therefore improve liquidity.

There are a number of issues related to the administrated determination of DC prices:

1. No risk premium included – The current process may not reflect the true market value of the forward contracts. There is an intrinsic value of the contract which reflects not only the expectation of future DAM prices but also the certainty that a contractual position may offer. The value of this certainty is not captured in the current process and may be rated differently by different market participants.
2. No reselling – It could be the case that the item 1 discussed above may be leading to a price of DCs which are lower than what the market would price. An evidence of this is the absence of secondary trading of this product. Overall shortage of hedging products is also another possible cause for this.
3. Finally, the current allocation process requires existing metered load in order to make a supplier eligible to get an allocation. This could act as a barrier to entry for new suppliers, as they need to acquire a certain volume of load before they receive an allocation of DCs.

2. Allocation of Directed Contracts – by auction

An alternative method of distributing Directed Contracts maintains the volume calculation of the obligation set out above but changes the method of allocation. In this design the RAs do not determine the price of the Directed Contracts, which is set at a competitive auction, but do set a reserve (minimum) price which would be modelled by the RAs in a similar fashion to current Directed Contracts.

This modelling would again reflect an RA calculation of the competitive price in the DAM and while the risk of mispricing by the RAs remains its consequential impact is reduced in this option. The existence of this reference price in the auction would continue to allow the Directed Contracts to effectively address concerns about market power but would allow the market to ultimately determine the value of the forward hedge. To this extent it might be expected that, in so far as valuations differ among participants and change over time, this might lead to trading of these contracts making some contribution to liquidity in the forward market.

The auction and further trading involved in this option could in addition contribute to, and derive benefit from, the central trading mechanisms set out in Section 6. It may also be the case however that, in an overall net short market, the price of Directed Contracts may be bid up, which may reward ESB due to its size in the market while insufficiently mitigating the concentration represented in the market by ESB, which is achieved by the current methodology. This would also have implications on the original purpose of DCs, which was to remove incentives on the dominant parties to raise prices in the prompt market.

There are a number of aspects of a market based mechanism for determination of DC prices which worth consideration:

1. New Entrants – A market based mechanism for allocation of DCs should benefit suppliers that are not currently established in the market as it would not depend upon existing metered consumption.
2. Market Liberalization – Market participants which values forward contracts the most would be willing to pay premium and hence would acquire volumes of DCs which are proportional to their valuation of this product.
3. Issue to be addressed – Electric Ireland participation in potential auction of DCs would have to be considered. This issue is discussed within the section 9 in the context of ESB's ring-fencing arrangement.

4.2 RING-FENCING ARRANGEMENTS ON VIRIDIAN AND ESB

Two groups of companies are currently subject to ring-fencing in the SEM - ESB and Viridian, which provides for separation of the generation and supply businesses.

The ESB Group includes generation and supply companies with significant market shares, which lead to the regulatory requirement for ring fencing between the generation company ESB and the Supply (Electric Ireland).

The ring fencing requirements within the Viridian Group are on the Power NI supply company which is the incumbent company in NI and subject to price control regulation were it retains a dominant position.

Ring fencing is also applied to The Power Procurement Business (PPB) within the Viridian Group. PPB is a business set up to act as a counter-party to a number of Generator Unit Agreements (GUAs). The GUAs were set up as part of electricity privatisation in 1992. PPB is responsible for purchasing the capacity of the contracted generating units as well as any electricity generated by those units on terms specified in the agreements. A number of these original GUA contracts have

now been cancelled, the residual contracted capacity is now limited to just under 600MW. The ring fencing licence requirement is necessary for the continued price control of PPB and not a requirement because of any dominance in the SEM/ I-SEM.

Also within the Viridian Group is Energia, which owns both supply and generation. There is no required ring fencing within this group, however the Energia Supply business is subject to licence requirements that enforce accounting separation so that accounting records are kept in a manner that would be maintained by a separate company.

The requirement for and limited nature of ring fencing within the Viridian Group has us conclude that further consideration of it is not relevant in the context of promoting liquidity.

However, the potential measures to promote liquidity in I-SEM that are subject to this consultation give rise to robust consideration of potentially different approaches to maintain the requirement for ring fencing within the ESB Group which retains a large market share in the both Generation and Supply. The issues raised and their implications are discussed in this section.

1. Role of Ring-fencing in SEM and I-SEM

The SEM Committee understands that while participation in the forward market is voluntary there is a strong desire for market participants to trade in this timeframe, which coupled with the current structure of the market, means that barriers to the entry and growth of independent generation and supply will still exist. Low liquidity can inhibit trading, price formation and enable barriers to exist that may limit new investment.

Vertical integration by companies can provide a financial hedge against potentially volatile wholesale energy prices and a natural hedge against balancing risk. It can reduce the incentive to trade with third parties, reducing the robustness of forward market prices. It also means that integrated suppliers may have stronger credit ratings that reduce the level of collateral that they may need to post. This provides obvious advantages compared to independent suppliers, although it also provides potential for efficiencies to be passed to consumers. In the context of the forward markets, the ring-fencing arrangements are currently a mitigation of these characteristics of vertical integration.

Ring fencing is a market power mitigation measure that separates generation from supply and prevents vertically integrated companies from internally hedging forwards while foreclosing this market to other market participants. It can help prevent the ring-fenced party passing profits from one side of the affiliated company

to the other by facilitating identification of abnormal profits on one side of the business. Profitability analysis is therefore carried out regularly by the RAs and, while it is recognised that there is no precisely defined objective test of what normal profits should be, the analysis by the RAs has been considered useful in providing transparency to the market.⁹

The I-SEM spot market design limits the ability of vertically integrated undertakings to foreclose markets to the detriment of either independent generators or suppliers. The development of additional markets however increases market participant costs of participation and the value of efficiencies to be gained by integration of group companies with both a generation and supply business.

The RAs must therefore be conscious of the advantages and drawbacks of vertical integration while also taking account of the competitive dynamics existing in the new spot markets and the market power mitigation tools available to them, which includes REMIT. The scope for enhanced volumes of FCOs and efficiencies achieved through vertical integration to be passed on to consumers must be set against the protection afforded to the market through the restrictions imposed by vertical ring-fencing.

In making this assessment it is appropriate that the two currently vertically ring-fenced companies are considered separately, taking account of their relative size, position in the market and potential disadvantages and benefits of any decision to remove ring-fencing.

2. ESB group

The ESB Group includes generation and supply companies with significant market shares. In 2015 ESB comprised 46% of the Market Scheduled Quantity of generation while Electric Ireland accounted for 38% of the all-island supplier volume. ESB is subject to vertical ring-fencing, which is enforced by licence.

Ring fencing of ESB has been considered appropriate in the SEM given the structure of the existing market. It enforces accounting separation and operational and managerial independence of the generation and supply businesses, providing transparency to the market that there is not unfair discrimination (by ESB Generation between Electric Ireland and other suppliers). The ESB generation licence also allows for the sale of Directed Contracts and prohibits anti-competitive

⁹ See the Generator Performance Report in the Single Electricity Market (SEM) [SEM-14-111 19](#) December 2014.

behaviour, cross-subsidy of other companies within the Group and disclosure of commercially sensitive information.

The I-SEM High Level Design Decision Paper has determined that the I-SEM Intra-day and Day Ahead markets will be unconstrained and will have unit based bidding. Within the Market Power Decision Paper, the SEM Committee has determined that ex-ante bidding controls will be implemented in the balancing market if observed behaviour is deemed to warrant intervention while non-energy actions will have an explicit ex-ante bidding control applied. Further, a FCO should be imposed upon ESB to mitigate market power in the I-SEM spot market. In this context, consideration is being given to the potential tradeoffs and gains for consumers from removing the ring fencing requirement.

However, even with the prohibition of physical self-supply, a vertically integrated Group could internally hedge against potentially volatile wholesale energy prices and have a natural hedge against balancing risk. Additionally vertical integration would reduce the incentive to trade and help perpetuate the barriers to entry that result from an illiquid forward market. These would therefore have the effect of foreclosing the market to other market participants.

3. Conclusion on ring-fencing arrangements

Ring-fencing arrangements will be revisited in light of the options to promote liquidity described in the Section 9. This issue is being considered in this area of I-SEM policy development exclusively from the perspective of promotion of liquidity. Notwithstanding that, mitigation of market power will receive close consideration by the SEM Committee.

5 SCOPE FOR INTERVENTION ON I-SEM FORWARD MARKET

5.1 HOW A REGULATORY INTERVENTION CAN DELIVER LIQUIDITY IN THE FORWARD MARKET

Given the competitive benefits of liquidity in forward markets, it is necessary to ask why market forces are not bringing about an efficient outcome. Regulatory intervention is justified where there is a market failure that can be rectified by such intervention. There are several reasons why markets may not deliver competitive outcomes:

- **Externalities.** If certain factors such as carbon emissions, for example, are not properly captured in the traded price then it is justified to intervene in the market to rectify this. Intervention need not be direct; in the case of renewables, a regulatory regime: REFIT in Ireland, and NIROCs in Northern Ireland can tilt the market in order to address the identified externality deficiency. However, in terms of I-SEM, there are no direct externalities to be addressed.
- **Regulatory interventions in associated markets.** Continuing with renewables supports, this can distort other aspects of the market. Wind farms are paid at a rate that covers many of the risks of trading in the wholesale market. In the case of REFIT in particular, as already noted, wind farms do not benefit from forward trading – they are hedged by the guaranteed price in their contract – and so a significant part of the spot market is outside the forward market, distorting the availability of hedging products from one side of the market. Similarly NIROCs have involved price support that reduces the need to hedge prices in the forward market. Another area of regulatory intervention affecting the market relates to financial trading rules brought in following the global financial crash; these raise the costs of trading and deter offering hedging products in some cases. In terms of I-SEM, encouraging more hedging products from non-REFIT parties may be an appropriate intervention.
- **Transaction cost and cost of new entry.** The electricity market is a complex undertaking involving specialist transportation issues and balance responsibility. The cost of setting up a trading function is high and the risks that must be covered where prices are fundamentally volatile are potentially large. Once set up, trading transaction costs can be high due to inefficiencies in the market. Regulatory intervention to address these risks are therefore of benefit.
- **Risk profile of hedging providers.** Many of the issues associated with market structure are discussed below. However, a specific structural issue relates to

reasons why many players may not have an appetite for forward hedging provision in the current market. A regulatory intervention to compel provision of hedging products already exists with regard to ESB, with this being associated with market power mitigation. Wider intervention to force a transfer of risk from hedging users (suppliers) towards potential hedging providers (generators) may therefore be justified.

- **Market structure.** There are clear benefits to incumbency in a market, which raises barriers to new entry. This does not prevent new entry where well-funded competitors can attack the market but it does increase costs, which at least slows the market. In a small market like Ireland, the benefits to the well-funded competitor may look unappealing, reducing the extent of competition development or else slowing it considerably. In all deregulating markets, some form of regulatory intervention has been found necessary. The market in Ireland and Northern Ireland has found it necessary to restrict the activities of the initial incumbents through DCs, ring-fencing and bidding codes of practice but this has only partly led to restructuring. In the GB market, even with six large vertically integrated competitors, the barriers to entry for new entrants remained high, with availability of forward prices proving a considerable obstacle, which is being addressed through a market making obligation. Moving forward into I-SEM, other interventions may be needed to address the implications of inefficiencies caused by market structure.
- **Immature market.** I-SEM will be a new market with lack of direct price history. This imposes additional risks – especially on smaller parties with less capacity to manage that risk. Regulatory intervention can assist the market to develop trading functions and so become more efficient more quickly. Such interventions could be temporary.

Regulatory interventions can therefore address permanent areas of market failure or temporary ones. In the case of I-SEM forward markets, some of the reasons for market failure are semi-permanent, being rooted in market structure (changing slowly) and potentially chronic shortage of product (due to the volumes of wind now and to be expected in the future), but other reasons are more temporary, being related to market immaturity.

Interventions need to focus on flexible measures but some elements need to be more long-standing. They need to be focussed in three areas:

- Promoting an increase in availability of hedging products – this will partly address market structure issues and the adverse risk profiles currently perceived by potential hedging product providers;

- Promoting an increase in trading of hedging contracts – this would partly address issues of market immaturity but could also address market structure deficiencies;
- Facilitating reduction in transaction costs of trading – this last may not strictly be a regulatory intervention as a market provider, encouraged to enter the market with improved trading facilities would not require any addition to regulation. This would address issues of cost of new entry.

These objectives can be very different and so a combination of measures may be necessary. However, it is clear that currently there is a high risk of market inefficiency continuing in forward trading, which justifies regulatory intervention.

The consultation paper thus sets out proportionate and non-discriminatory options for regulatory intervention, which have the legitimate objective of promoting liquidity and addressing market power exercisable in the new market. These options arise from a holistic consideration of the market, including previous analysis by the SEM Committee on mitigation of market power, and an evaluation of the impact of the measures proposed taken as a whole. They include regulatory intervention to build upon steps that market participants might themselves seek to take, but which in themselves will be insufficient to provide a solution to market failure. In respect of the encouragement and facilitation of the introduction of mechanisms that would remove certain barriers to trading, regulatory intervention is confined to a facilitation role that is limited to that which is considered strictly necessary, so as to avoid distorting or blunting the commercial incentives that we are seeking to encourage.

Where obligations are placed on market participants these shall be implemented through licence condition on the obligated parties. The continued application of the licence condition shall be reconsidered at relevant times, taking account of the development of the I-SEM, the impact and effectiveness of the obligations and their continued appropriateness, taking account of all the relevant circumstances of the market participant and the market taken as a whole. Market participants shall remain free to seek removal of the obligations from the license by written request to the Regulatory Authorities with full argumentation and supporting evidence. Such requests will receive the full consideration of the RAs in the manner by which they will carry out their own periodic review.

Developments under EU Markets in Financial Instruments Directive (MIFID II) should define forward electricity products as financial instruments to be subject to the requirements of financial regulation. It may be the case that those participating in electricity markets are subject to energy and financial sector regulation. This may be the case despite trading in such products being an ancillary activity of the market

participant which arises at least in part from the intervention of the RAs. Market participants may want to advise the RAs of the costs that would arise and what steps might be taken to mitigate them by the RAs and also by the market participants themselves, including by the possibility that obligated parties could opt to appoint a third party to perform certain obligations.

5.2 MEASURES TO PROMOTE LIQUIDITY IN THE I-SEM FORWARD MARKET

In reviewing regulatory interventions, three possible options to be used separately or in combination are reviewed. These are discussed briefly below and in more detail in the sections that follow:

Removal of barriers to efficient trading

This element is likely to be more a facilitation than an intervention provided an efficient voluntary route service provision can be found. The main barrier is the cost of setting up bilateral trading arrangements and the collaterals that must be provided for each trade. This measure would seek a trading platform, a central counterparty for trading and a central credit provider to allow multilateral trading and netting of collaterals. This should do something to reduce cost and also reduce barriers to trading, thus facilitating liquidity. The Section 6 of this Consultation Paper will discuss the proposed approach for the removal of barriers to trade in the I-SEM forward market.

Forward Contract Selling Obligation (FCSO)

Given the reluctance of generators (other than, mainly ESB) to offer hedging products to the market, this intervention would require all but the smaller generators to offer CfD contracts to be backed by the physical positions they could take in the DAM using in-merit dispatchable generation. These CfDs would be offered at auction into a fundamentally short market (in terms of demand from suppliers for hedging products).

It is recognised that this creates a risk for generators that they were not voluntarily intending to take at this stage. However, given that they also benefit from hedging their businesses against DAM price volatility and underlying change, and given that the market for hedging product is still likely to be short, the risks of under-pricing such products is small and consequently, the risk imposed on these generators may be considered proportionate.

Market Maker Obligation (MMO)

The MMO is applied in GB but in most organised markets, market makers have evolved without regulatory intervention, with the only incentive being a reduction in

trading fees from the market provider. It should be noted that market makers also perceive a benefit from the increased liquidity in the market that they themselves are promoting through market making.

A Market Maker (MM) is required to post buy and sell prices across much of the entire forward curve at a maximum price spread. If a party trades at one of the prices posted, the MM is required to repost prices, but can re-price as long as it does not exceed the maximum price spread.

This puts pricing risk onto the MM but ensures that all parts of the market can trade into or out of positions without unduly moving prices and hence provides additional liquidity to the market. Because the MM can re-price regularly, risks are likely to be manageable. Given that the MM would probably be in the market for hedging products, these risks can be considered proportionate.

Being an MM suggests the need for a strong financial position. This means that a MMO should be placed on larger businesses only. Because the obligation is to both buy and sell, it is beneficial (but not crucial) if the obligation is placed on businesses with a degree of vertical integration.

Direct Contracts to mitigate market power in the spot market would still apply in conjunction with any of the intervention discussed above. Section 4 discussed the approach for determination of volumes and prices for these contracts.

6 REMOVAL OF BARRIERS TO EFFICIENT TRADING

6.1 TRADING BARRIERS FOR THE I-SEM FORWARD MARKET

The current market for SEM CfDs is bilateral. The sale of PSO related and non directed CfDs for the SEM was initially carried out by the sellers in an auction, where bidders faxed in their orders. Later these trades were carried out through a broker, Tullet Prebon, and the auction rules between the two main sellers became more standardised and the process more automated. In 2011 an over the counter market was established for SEM CfDs and ESB, the largest seller, has moved from selling NDCs in auctions to this sale format.

One of the biggest costs facing suppliers purchasing CfDs is the credit cover required by the seller. The level (15%) and the separate lines of credit needed for different contracts are not the most efficient arrangement and increases costs and/or limit trade. A pool arrangement for credit across different contracts with the same seller or through a centralised platform would help reduce costs and could be achieved through a clearinghouse.

Exchange based trading provides an alternative to bilateral or over-the counter (OTC) trading. Exchange based forward contracting provides security for market participants by acting as a counter party to all trades, allowing credit arrangements to be centralised. Power Exchanges utilize auctions and are sometimes called auction markets. An advantage of auction markets is that one need not find the best price for a product because the Power Exchange interposes itself between buyers and sellers.

An exchange can have a number of advantages over the current bilateral market. It can reduce trading costs, increase competition, and produce a publicly observable price. Lowering the costs of carrying out trades of electricity CfDs should encourage greater liquidity and increase the opportunity for smaller and new entrants to the market. These costs include the fees paid to brokers or power exchange trading fees, credit cover, as well as any of the other contractual or regulatory requirements involved in trading.

In terms of challenges, a power exchange would require a minimum number of participants and volume of trades to be economically viable.

The following main trading barriers are anticipated for the I-SEM forward market:

- Price discovery:
 - NDCs are negotiated privately outside any regulatory purview. Therefore price discovery is a concern as details are not known to the wider public.

- Susceptibility to defaults if prices are not favourable:
 - I-SEM market parties experience a lack of an effective deterrent as there is no regulation or rules governing forwards contracts.
 - As there is no standardised counter party risk guarantee, coverage for counter party risks must be negotiated on a bilateral basis.
- Barriers to entry
 - The bilateral nature of forward contracts and large scale counter-party risks prevent small players from entering into a forward contract due to a lack of trust. Parties minimise this risk by limiting their counterparties to those that have been pre-vetted.
 - For any deal entered into, parties impose high credit coverage requirements.
 - Due to the obligations imposed on bilateral trading, transaction costs are high (e.g. EMIR/REMIT obligations). This discourages marginal trades, thereby reducing liquidity.

Generally, high credit cover requirements are perceived as a trading barrier for small parties in participating in all segments of the I-SEM, including not only the financial forward market but also the FTR market and the physical day ahead and intraday markets.

6.2 POTENTIAL SOLUTIONS

Central service provision has been identified as a potential solution for the identified I-SEM trading barriers.

Three types of central services could provide potential solutions. Integration of provision of these services for the forward market with central service provision for other I-SEM market time frames and products (FTR, day ahead, intraday and balancing markets) forms a potential extension of this solution.

Figure 8 shows how these services may form together a complete trading arrangement for organized trading. The key elements are discussed below.

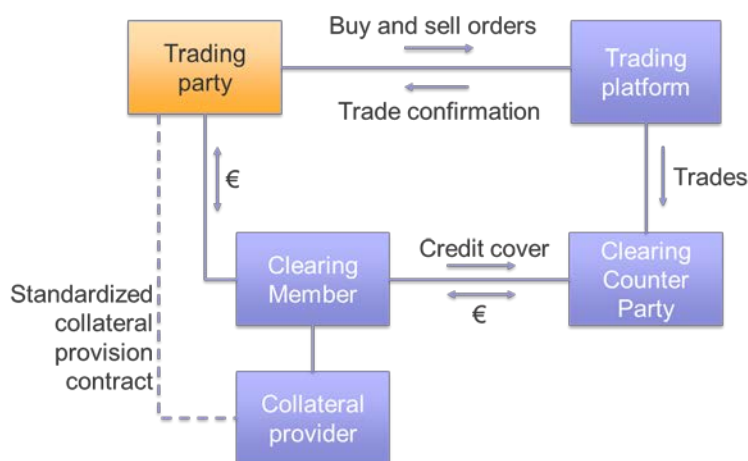


Figure 7: Trading and credit services in organised markets

Central clearing counter party

A central clearing counter party (CCP) performs the clearing and settlement of all trades concluded on a central trading platform. Parties trading on the central platform must engage into a clearing arrangement with the CCP. The CCP usually requires trading parties to be represented by a Clearing Member. In addition, a CCP can offer a direct clearing facility which does not require a Clearing Member. In all cases, a CCP requires credit cover which must be either provided by the Clearing Member or by a Collateral provider in case of direct clearing.

A central clearing counter party for all forward market trades would potentially:

- Lower counterparty default risks by acting as a counterparty for all trades;
- Lower the costs of clearing by efficiency gains from centralisation;
- Lower the costs of credit by standardised collateral requirements.

The business case is generally covered by the profit from provided collaterals and/or clearing service fees. Clearing facility, clearing frequency, collateral requirements and clearing fees are the main competition factors between CCPs.

Central trading platform

A central trading platform potentially offers the following advantages:

- anonymous trading;
- price discovery by displaying quotes;
- fulfilment of transparency obligations (e.g. EMIR/REMIT).

Central trading platform services could be provided for both auction based trading as well as for continuous trading.

The business case of central trading platforms is covered by membership fees and trading fees. Besides membership fees and trading fees, the offered trading facilities are the main competition factor between central trading platform providers.

Central collateral provider

A central collateral provider can offer coverage for collateral requirements for the clearing of trades through a CCP against standardised conditions and creditworthiness requirements. Any party meeting the standardised creditworthiness requirements and willing to pay the standard service fee could thus get access to the central collateral provider service. The central collateral provider must be a Clearing Member of the CCP and should in addition offer credit coverage for direct clearing services if offered by the CCP. The central collateral provider must offer a Clearing Membership with any of the foreseen I-SEM CCPs.

Integration of central services

In addition to each of the central services described above, integration of central services through the different market timeframes and products could offer more favourable service access conditions and lower total transaction costs.

Integration advantages are expected from integration of services over market time frames and products, one central trading platform and one central collateral provider for all market time frames and products.

6.3 TYPE OF TRADING – AUCTION OR CONTINUOUS TRADE

Futures markets where standard forward products are traded on a trading platform are usually of a continuous trade type. Exceptions occur especially in situations where the nature of demand or supply requires an auction type approach: i.e. the demand or the supply curve does not have any price elasticity. This is for example the case with DCs but also with long term transmission rights like FTRs or PTRs.

FCOs would have a fixed price, so this kind of liquidity measure would require an auction type of trade.

MMOs fit only within a continuous trade market.

So the answer to the question of the need for a continuous or auction type of trading is driven by the choice of liquidity measures to be implemented.

6.4 PRODUCTS REQUIRED (TIME-OF-DAY, SEASON, MONTH, ETC.)

Here the prevailing products for the SEM forwards may be followed. Based on SEM results for NDCs, the products traded and their popularity are as follows:

Baseload	Seasonal (and multi-year)	Not traded
	Quarterly	Popular
	Monthly	Popular
Mid-merit	Seasonal	Not traded
	Quarterly	Some popularity
	Monthly	Some popularity
Mid-merit 2	Seasonal	Not traded
	Quarterly	Intermittent popularity
	Monthly	Intermittent popularity
Peaking	Seasonal	not traded
	Quarterly	Intermittent demand
	Monthly	Intermittent demand

Based on European experience of both physical and financial forward markets, the most popular products are usually baseload types. This is consistent with markets where the primary interest is in protection against underlying price movement. In this respect, there may be an emerging need for longer-dated seasonal products as has been seen in the GB market and which has been requested by various participants.

While changes in the underlying reference price for contracts in the I-SEM mean that the past may not be a good guide to the needs of the market going forward, this European experience suggests that the basic SEM products currently available should continue, although there is a risk that some of the products may not be adequately liquid.

6.5 VOLUNTARY SERVICE PROVISION POSSIBILITIES

The central trading services discussed are commercial services that are not provided under licence or subject to energy regulation. Their operation provides for the provision of services that allows market participants to trade more efficiently, supporting their commercial objectives and providing the premise for charging by the service provider. On this basis it is not considered appropriate that the RAs should seek to procure these services or seek to create arrangements in which consumers would underwrite them. The facilitation of voluntary provision is therefore considered the appropriate route for procuring the services.

It is assumed that trading for the first I-SEM forward market delivery period should start no later than May 2017.

Forward trading services could be added to the current trading services provided for operation of the DAM and IDM as part of the NEMO responsibilities. In this option there may be limited advantages to merging forward trading platforms in the different timeframes with greater efficiencies arising in provision of the CCP and central collateral provision.

It is expected that service providers would generally require up to 6 months to set-up the required services for I-SEM and up to 6 months for market trial of these services. A go-live of required service is anticipated to be required by May 2017. That means that a procurement strategy which requires at least another 6 months for procurement would not lead to timely implementation for I-SEM. Therefore a voluntary service provision is the preferred approach to implementation. The RAs will request expressions of interest from potential providers that may be interested in providing required central services on a voluntary basis.

JAO will provide central clearing of the FTRs that it will auction for the Interconnectors as well as for any subsequent secondary market trades in FTRs. The current FTR products are options and so the collateral requirements will differ in comparison to the two-sided payments on CfDs in the forward market. Integration of CCP service provision for the FTR market with the I-SEM forward market could offer synergies by a reduction of net collateral requirements over both markets. However, CfD clearing is not JAO's core business and CCP service provision for CfDs might not be feasible for JAO. The development of the JAO platform by the interconnector owners follows the RAs' policy decision on the form and attributes of FTRs and IC owners report regularly on progress to the I-SEM governance framework.

Any other clearing function is not foreseen in the I-SEM forward market and other than the benefits from a central counterparty combined with a trading platform for the forward market alone, other CCP service providers will not be able to offer integrated clearing services with other market timeframes and products. As the products traded differ over the market time frames there seem to be few synergies to be expected from trading platform service integration over market time frames.

Potential providers may want to offer CCP services in combination with a central trading platform service like ECC with EEX, Nasdaq/OMX or the provider of the existing SEM forward trading platform: Tullet Prebon.

The RAs are engaged in a separate exercise as part of the Forward and Liquidity workstream to encourage and facilitate provision of these services on a voluntary basis. This has involved identification of service user requirements and discussions with potential service providers. This work will continue in parallel with the policy decision making consulted upon in this paper:

- Each of the services described forms a building block of a complete trading arrangement for the I-SEM forwards market
- The exact configuration will depend on the service providers that are willing to engage for them on a voluntary basis
- A target solution that includes a PX-like trading platform with CCP services will be sought
- Procurement or regulatory underwriting for any of the mentioned services is excluded.

7 FORWARD CONTRACT SELL OBLIGATION (FCSO)

Having discussed the issues which prevented liquidity to grow organically in the current SEM and how these issues could still play a role in the I-SEM forward market, the SEM Committee is now considering interventions in the I-SEM forward market; this section discussed the first possible intervention which is a Forward Contract Selling Obligation (FCSO). This intervention relies on the removal of trading barriers and the establishment of a platform that supports the auctioning of products.

A FCSO would be a regulatory intervention on the forward market by mandating minimum volumes to be sold by generators in the forward market. An FCSO to address liquidity shortfalls would apply broadly to generators. It would be determined in the following steps:

Determination of Aggregate Cap on FCSO obligation:

- Assess supplier demand for hedging products as forecast off-take over any period;
- Discount supplier demand for hedging by a defined percentage representing a proportion of prompt delivery that they would reasonably wish to remain unhedged. On this basis, **[10%]** of un-hedged demand is reasonable.
- Proxy hedges from fuel derivatives are assumed to cover up to **[20%]** of the supplier demand for hedging. Although it is most likely that generators will use proxy hedges rather than suppliers, it seems reasonable that space be allowed for this within a FCSO.
- Suppliers can also seek hedging products from other market zones such as the GB forward market. Up to 6.34 TWh in aggregate could be sourced from GB via a combination of FTRs (on both interconnectors) and CfDs products. This represents almost **[20%]** of the total demand.
- In developing an Aggregated Cap on FCSO, supplier demand for hedges needs to be further discounted for the DC and PSO obligation on ESB. In 2015 DCs and PSO volumes were 3.92 TWh and 2.48 TWh respectively which represented almost **[20%]** of the demand. These volumes will vary for different years as ESB's share of generation market fluctuates upwards or downwards.
- Considering the points above the overall Hedge Ratio (*H_RATIO*) that the supply market should expect to receive from an obligation on generators, including DCs and PSOs, is around **[50%]** of the overall demand (20% of DCs + PSOs and 30% FCSOs).
- It is worth note that in relation to DCs, ESB would be allowed to partially meet its forward selling obligation by selling DCs. As the volumes of DCs

would be expected to fluctuate up or downwards from year to year, ESB's FCSO would be primarily determined by its share in the generation market, what could change from year to year is the proportion of this obligation met by DC volumes.

- Hence, using 2015 data as an example, the Aggregated Cap on FCSO (AC_{FCSO}) would be calculated as follows:

$$AC_{FCSO} = (F_{DEMAND} * H_{RATIO}) - DCs - PSOs = (32.9TWh * 50\%) - 3.9 - 2.48 = 10.07TWh (30\%)$$

Where:

F_{DEMAND} is the Forecasted Demand for the period to which the FCSO would apply, using data from 2015 it equates to 32.9TWh.

- Note that all parameters in the Aggregated Cap on FCSO will vary according to forecasts, including changes in output from ESB owned plants and any PSO supported generations.

Determination of total available generation to provide hedging:

- The RAs would determine on a forward looking basis, volumes to be offered.
- Error! Reference source not found.** shows the Market Scheduled Quantities for 2015 assigned to generators. In this analysis, hydro and wind farms are excluded (6.8 TWh), as is the MSQ of interconnector volumes (3.8 TWh). This results in a total MSQ of about 24.2 TWh as against spot sales of over 35 TWh.

	MSQ 2015 (TWh)	Share
ESB	14.62	60.4%
Bord Gais	2.59	10.7%
AES	1.68	7.0%
Aughinish	1.34	5.5%
Tynagh	1.26	5.2%
SSE	1.22	5.0%
Bord na Mona	0.81	3.4%
PPB	0.31	1.3%
Energia	0.17	0.7%
Others	0.15	0.6%
DSU	0.04	0.2%
First Electric Ltd	-	0.0%
Grand Total	24.20	100%

Table 7: Dispatchable generation by company, 2015

Determination of methodology for bringing contracts to market:

- The FCSO as an obligated contract at standardised terms needs to be sold at monthly auctions rather than OTC.

- Given the moves to improve the environment for trading and collaterals and given that multiple parties will be required to offer contracts under the FCSO, the SEM Committee is of the view that an auction on a cleared basis should be provided for.
- Given the asymmetry of incentives to trade forward contracts discussed in the preceding sections, the SEM Committee is of the view that generators should be price takers in these auctions.

Determination of the products to be offered:

- Bearing in mind the larger volumes of FCSOs compared to the current NDC market and the consequent credit implications of this, the SEM Committee is of the view that monthly CfDs should be offered at each auction to allow suppliers to manage their cashflow.
- Reviewing the analysis at the end of Section 3.5, it might be concluded that the MW ratios of products to be auctioned should be: baseload/Mid merit/peaking = 12/4/1.
- However, it may not appropriate to assume that time-of-day risks will be perceived as the same in the DAM compared to a ex-post pool and so there should initially be greater availability of non-base load products in the mix; the SEM Committee proposes a ratio of 2/1/1 that mirrors the decision relating to DC contract allocation in the current market.
- Market Participants are invited to submit their views on the appropriateness of the 2/1/1 ratio.

Determination of which generation companies are not required to provide FCSOs:

A generator required to offer contracts at auction would face the parameters in Table 7:

	Sale per auction lot (MW)	Auctions per year	Months of product delivered per auction	Hours of product delivered per week per MW per auction	Hours of product delivered per year per MW per auction	MWh per year
	(1)	(2)	(3)	(4)	(5)	(6)
Base load	2	12	12	168	8,760	210,240
Mid merit	1	12	12	70	3,650	14,600
Peaking	1	12	12	20	1,043	4,171
Total	4		12		13,453	266,554

Table 7: Calculation of minimum delivery commitment under FCSO

At each auction, the auction lots would be 2 MW of baseload and 1 MW each of mid merit and peaking. Each lot would further be for one of the next 12 delivery months

for a full month of CfD. Because each product would vary in terms of delivery hours and delivery days, a different number of hours would be delivered for each product over the 12 months of delivery (column (5)). To arrive at the total annual commitment of a generator offering lots of two MW baseload and one each of mid merit and peaking (column (6)) we multiply columns as follows:

$$col6 = col1 * col2 * col5$$

This gives a minimum requirement per generator of 267 GWh per year. The de minimis threshold for generator participation should therefore be **267 GWh** of expected dispatch of dispatchable generation.

Setting FCSO on remaining companies:

Setting the FCSO requirement and provision by each company using the supplier requirement (16.45 TWh, which includes DC and PSO volumes) and allocating the aggregate obligation pro rata to the shares of total expected MSQ of dispatchable generation, the following volumes of FCSO would be obtained (using data of 2015). PPB would be the last generator above the de minimis level. Note that for ESB, the FCSO volume would have deducted from it any volume sold of DC or PSO contracts, resulting in a net FCSO. While the ESB's net FCSO could fluctuate based on volumes associated with DCs and PSOs, their gross FCSO would be based on their of the generation market. Which means that if DC and PSO obligation were to disappear in some point in the future (due to eventual reduction of ESB market share), then ESB Net FCSO would be the same as their Gross FCSO.

	MSQ 2015 (TWh)	Share	Gross FCSO	DCs	PSO	Net FCSO
ESB	14.62	61.33%	10.09	3.9	2.48	3.71
Bord Gais	2.59	10.88%	1.79			1.79
AES	1.68	7.06%	1.16			1.16
Aughinish	1.34	5.61%	0.92			0.92
Tynagh	1.26	5.31%	0.87			0.87
SSE	1.22	5.12%	0.84			0.84
Bord na Mona	0.81	3.41%	0.56			0.56
PPB	0.31	1.29%	0.21			0.21
Grand Total	23.84	100%	16.45			10.07

Table 8: Calculation of generator volumes under FCSO

Risk exposure of providers

As noted above, a generator has partial exposure to unavailability when it sells forward because it is then unable to use physical generation to offset any payout made on a CfD. However, it should be remembered that the exposure is to a CfD and so the exposure is always to the difference between the strike price of the CfD and

the DAM reference price; whether the generator is dispatched in the DAM or not the exposure is limited to this price difference.

The exposure could increase where the generator loses a large unit before the DAM opens because this is more likely to make the whole system short, increasing the potential imbalance cash-out price and making the DAM price rise in anticipation.

However, in reality, this is only a critical exposure in an illiquid market because otherwise, the generator could seek to buy out of an exposed position as it arises, capping its losses on the CfD. Given the expected greater volatility in the DAM and the likely higher prices than in the ex-post pools at some times, generators in the new market will have a greater incentive to trade forward in any case.

Expected effect of FCSO

On average 70% of the I-SEM dispatchable generation should be sold under FCSO. The FCSO on its own will not increase substantially the volumes which are currently traded in the forward market (see section 3.2 for volumes traded in 2015). However the FCSO will improve market liquidity to the extent that selling obligations would be spread across a larger number of market players. In addition, Market Participants which now have an internal hedge would be required to externally trade some of that internal hedge. The advantage of this approach is that it makes the price formation in the forward market more robust.

8 MARKET MAKER OBLIGATION (MMO)

The nature of market making is that it is a two-sided business, with prices necessarily quoted for both buy and for sell. As such, a market maker is not necessarily a generator or a supplier, although vertical integration will strengthen the capacity of the market maker to offer terms; the key requirement is financial strength to take on a market maker risk.

The market objective for a market maker is that price quotes for specified products are always available for trading rather than that a certain minimum liquidity level is reached. The business objective of a market maker is to profit from trade, generally per unit traded through the difference between ask and bid price, also known as the bid/ask spread.

Given the two sided obligation (Buy and Sell) on market participants, 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 acknowledge that, ultimately, it is the financial strength of the market maker that supports the activity and not their physical position in the market. Potentially, a completely non-physical party could establish a market-maker function in offers of CfDs, which are purely financial products. However, in the context of a regulatory intervention, it is reasonable that it be applied on market participants with significant market shares. Therefore, this measure would work more efficiently within a scenario where ESB is allowed to be vertically integrated. Therefore this intervention relies upon the Removal of Trading Barriers and removal of the ring-fencing of ESB)

The following sections will illustrate the framework for the determination of the Market Maker Obligation. The volumes presented are based on 2015 data and therefore are only illustrative and aim to explain the mechanisms that would be utilised to determine the level of obligation that would be assigned to each market maker. For the actual mechanism, volumes will be calculated via forecast of year ahead volumes.

General market maker concept

Generally, market makers add to liquidity by being ready to buy and sell designated securities at any time during the trading day. For example, market maker MM in a stock – let's call it Alpha – may show a bid and ask price of €40 / €40.05, which means that MM is willing to buy it at €40 and sell it at €40.05. The spread of 5 cents is its profit per share traded. If MM can trade 10,000 shares at the posted bid and ask, its profit from the spread would be €500.

Rather than tracking the price of every single trade in Alpha, MM's traders will look at the average price of the stock over thousands of trades. If MM is long Alpha shares in its inventory (bought more than it sold), its traders will strive to ensure that Alpha's average price in its inventory is below the current market price (by reducing the ask price) to ensure that its market making in Alpha is profitable. If MM is short Alpha, the average price should be above the current market price, so that the net short position can be closed out at a profit by buying back Alpha shares at a cheaper price (by increasing the ask price and decreasing the bid price).

To manage risks, market-maker spreads would widen during volatile market periods because of the increased risk of loss (buying at a higher price than it can be sold for later, selling at a lower price than it can be bought for later). Wider spreads are a way to dissuade investors from trading during such periods. With a cap on the spread through a market maker contract or a market maker obligation, the spread cannot be used for risk management and other provisions may be allowed to cap the market making risk.

For the UK futures market for example, the MM risk during each market making trade window is capped by a limit to the net position traded out of the quotes and by the price increase or decrease of trades after the first trade.

In the New Zealand futures market, the risk is capped by a re-quote obligation for a lower volume and more generally by allowing suspension in case of a stressed market situation. As MM in the NZ futures market is contracted by the exchange and the contracts are not public, the exact definition that applies for a stressed market situation is not known. Appendix I covers in more detail the International experience with Market Making Obligations.

How many market makers in a successful market?

A market could operate successfully with a single market maker but this is not common because of the risks faced by the single market maker. Market makers take risk positions and need ways of controlling their exposure. With more than one market maker, it becomes easier for any individual market maker to lay off risks and thereby control exposure.

New Zealand has four voluntary market makers, which was judged sufficient by the New Zealand regulator, a fifth potential market maker did not want to offer market making services, citing a view that the risks it faced were disproportionate in comparison with the businesses that volunteered. In the larger GB market, there are six obligated market makers but this is more a function of the structure of the GB market than a requirement for a minimum number.

In general, the greater the number of market makers the smaller the likely price spreads between buy and sell offers, which is better for liquidity. This also reduces the market maker risk by enabling them to trade out of uncovered trades at a lower price.

Given the roles of market making, the objective is to improve the robustness of price discovery as well as facilitating reduction in price spreads and facilitating liquidity.

- A single market maker will effectively set prices, which reduces confidence in price discovery; a second market maker would have a benchmark from the first and this would improve price discovery but there is still a strong risk of price signalling between the market makers that would reduce confidence in the resulting price. A third market maker would help to give due confidence in the prices achieved through competition between the market makers. Price signalling remains a risk, and a further market maker will reduce this risk while beyond this diminishing benefits will be found.
- A single market maker would need wide bid-ask spreads in order to control its risk, partly because it would be faced with poor confidence in price discovery. A second market maker would improve this significantly because each could lay off risk with the other. Introducing a third market or fourth market maker will further improve this and introduce the competition needed to reduce spreads.
- A market maker will improve liquidity by offering prices across the curve. Introducing a second market maker will add further to liquidity through reduction in bid-ask spreads and through improved confidence in price discovery; a third and then fourth market maker offers further improvement.

Liquidity and competition generally will be improved as more market makers and traders enter the market, it is a virtuous circle. However, market making remains a risk and although this risk diminishes as more market makers are introduced (and more traders generally), it remains necessary to only impose an obligation on parties able to carry risks additional to general trading risks. The criteria for selection of market makers will be discussed in the subsequent sections.

Market maker obligation concept

A market maker enters into an obligation to quote buy and sell prices for a specified product during specified trading windows on each trading day that the product is traded for a specified volume of product. There can be one or more market making trading windows specified for each Trading Day. For forward markets market maker trading windows are typically with a 30 minute to one hour duration each. Market maker volume obligations for forward markets are typically from 5 to 10 MW.

The objective is to always have quotes available during the market making trading window, even if the quotes are traded. As FCSOs may be sold out and MMOs shouldn't, this means that MMO volumes contrary to FCSOs should in principle not be discounted for. Under circumstances this might lead to unacceptable risks for the market maker, hence limitations on re-quote obligations may be allowed. There are several variances to limit re-quote obligations within a market making trading window:

- Unlimited: when a quote is traded, it must immediately be replaced by a new quote for the specified volume
- Volume limit: A traded quote must be replaced by a new quote but only for a specified lower volume during the remainder of the trading window
- Net position limit: traded quotes must be replaced by new quotes for the specified volume until the net position traded out of the market maker quotes during a trading window reaches a specified limit
- Price change limit: the re-quote obligation is suspended if the price difference between the first and the last trade within the trade window is larger than a certain percentage.

The SEM Committee is of the view that, a price change limit and a net position limit are the most appropriate measures to apply. The SEM Committee invites market participants to express their views on this topic.

Benefits, costs and risks for the market maker

The risks faced by a market maker need to be viewed in context. One aspect of market making is that it is a route to market for that party's own hedging requirements. The party would be trading in hedging products anyway and should be dynamically managing its portfolio of contracts based on forecasts of average spot prices and forecasts of changes in its physical portfolio of both generation and off-take. Nevertheless, the requirement to continuously post prices will entail additional risks; the more liquid the market, the smaller that risk and so the market maker benefits also from the existence of other market makers.

Without a contracted or regulatory obligation market makers manage their risks by the bid/ask spread. They also earn their profits from the bid/ask spread. Costs are mainly related to the expertise and business processes to be put in place for proper risk management. Therefore, obligatory bid/ask price spread limits should be reasonable compared to the costs incurred.

Putting market maker obligations in place

Market maker obligations can be put in place through a contractual arrangement between an exchange and trading parties. In this case the exchanges and traders that enter into such a contract and the contract conditions are a negotiated result. As a consequence, the contracting exchanges, the contracted traders and the market maker obligations might not be optimal for the market concerned.

Alternatively market maker obligations are put in place on selected traders through the regulatory framework. In this case, the arrangement is independent from the exchange platform(s).

8.1 HOW IT WOULD WORK?

Let us assume a market maker obligation for a baseload product of 1 MW, which is traded during 12 calendar months ahead of the delivery period.

Let us further assume that forward trade takes place every business day with 5 business days per week and that there is one market maker window during each business day.

Now suppose that the market maker would have a net sell position of 1 MW after each market making window that the product is traded.

The market maker would then have to deliver for:

$$\begin{aligned} & 250 \text{ (market making windows per day of delivery)} \\ & \quad \times \\ & \quad 365 \text{ (days of delivery during calendar year)} \\ & \quad \quad \times \\ & \quad \quad 24 \text{ (hours of delivery per day)} \\ & \quad \quad \quad = \\ & \quad \quad \quad 2.19 \text{ TWh per calendar year} \end{aligned}$$

{This is for a trading period of 12 months ahead of delivery. For shorter trading periods ahead of delivery, this number should be corrected accordingly, i.e. 2.19/6 for a 2 months trading period ahead of delivery period etc}

Similarly, for a mid-merit product with 14 delivery hours per day on weekdays this would be:

$$\frac{14}{24} * \frac{5}{7} * 2.19 = 0.91TWh$$

and for a peak product with 4 delivery hours per day on weekdays this would be:

$$\frac{4}{24} * \frac{5}{7} * 2.19 = 0.26TWh$$

If the market maker would have a net sell position traded of 1 MW over all of these products (baseload, mid-merit and peak), his net sell volume to deliver would depend on the share of each product in the net position traded. Assuming a product share in the net position traded relative to the hours of delivery of the product per week, the average net position traded share would be:

- Baseload: 24 delivery hours per day, 7 days per week
- Mid-merit: 14 delivery hours per day (Mon-Fri 7am-9pm)
- Peak: 4 delivery hours per day (Mon-Fri 4pm-8pm)

$$Baseload: \frac{24 * 7}{(24 * 7) + (14 * 5) + (4 * 5)} = 0.65$$

$$Midmerit: \frac{14 * 5}{(24 * 7) + (14 * 5) + (4 * 5)} = 0.27$$

$$Peak: \frac{4 * 5}{(24 * 7) + (14 * 5) + (4 * 5)} = 0.08$$

Converting this to TWh net delivery per calendar year, an average 1 MW net sell position traded over all products per market maker trading window would boil down to:

$$0.65 * 2.19 + 0.27 * 0.91 + 0.08 * 0.26 = 1.69TWh$$

of net delivery per calendar year.

This demonstrates how to convert an average net sell trade position per market making window over all products into a TWh net delivery per calendar period. This conversion will play an important role in the setting of caps to the MMO volumes for the I-SEM forward market.

The objective of an MMO would be to always have an acceptable price quote for CfDs along the forward curve. This relates heavily to the qualitative definition of liquidity discussed in Section 2.3. If an acceptable price quote is always available, this would always allow a party to trade in or out of a position. However it would not in itself meet the other liquidity requirement, namely those prices should not change

much with every trade. For that, the price spread allowed and the volume of MMOs is important.

MMO volumes to be procured

The RAs will, year ahead, determine overall maximum volume of contracts that MMs would be required to make available. This caps the exposure of MMs collectively but does not prevent them offering more. As previously discussed, the capacity of a market participant to act as a market maker, is proportional to their balance sheet. As a proxy for the determination of the size of each balance sheet, the RAs will use forecast volumes of generation and supply combined.

- Using the 2015 results, Generation + Supply volumes total around 65 TWh as shown in Table 9, which, because the capacity to be an MM is based on financial throughput of a business rather than being based on hedging specific volumes using physical assets, includes non-dispatchable generation volumes.

	Generation	Supply	Net Exposure	Combined	Share
ESB	16,379,230	12,417,420	3,961,810	28,796,650	44.5%
SSE/Airtricity	3,142,298	7,229,250	-4,086,952	10,371,548	16.0%
Energia	1,514,663	4,662,428	-3,147,765	6,177,091	9.5%
Bord Gáis Energy	2,971,471	2,625,999	345,472	5,597,470	8.6%
Power NI		2,822,600	-2,822,600	2,822,600	4.4%
AES	1,682,278		1,682,278	1,682,278	2.6%
Aughinish	1,338,012		1,338,012	1,338,012	2.1%
Tynagh	1,264,480		1,264,480	1,264,480	2.0%
LCC/Go Power		1,078,100	-1,078,100	1,078,100	1.7%
Bord na Mona	1,047,528		1,047,528	1,047,528	1.6%
Vayu		392,217	-392,217	392,217	0.6%
PrePayPower		386,219	-386,219	386,219	0.6%
PPB	307,832		307,832	307,832	0.5%
Budget Energy		222,400	-222,400	222,400	0.3%
Firmus		20,100	-20,100	20,100	0.0%
Other generators	2,189,306		2,189,306	2,189,306	3.4%
Other suppliers		1,051,040	-1,051,040	1,051,040	1.6%
	31,837,096	32,907,773	-13,207,393	64,744,869	100%

Table 9: Company shares of combined generation plus supply MSQ, 2015

- Interconnector imports and exports are excluded as interconnector owners would not be subject to a forward contract obligation as the volumes and direction of flows on Moyle and EWIC are dictated by the market coupling process of the DAM.
- Suppliers with net exposure not covered by vertically integrated generation = 13.2 TWh (adding up just the negative values of Net Exposure), this represents roughly 20% of generation + supply

- The volume requirement can be expressed in a cap on net position traded over all MMs and products as elaborated in Section 8.1.

Allocation of MM Obligation to licensees

In general, it can be expected that, year-on-year, the obligation to offer MM services would not change. However, on occasion, a party obligated in one year may fall out of eligibility through a temporary or permanent change in their business or through a change in market share of another party that changes the ranking. Based on the figures in the table above, it can be anticipated that both ESB and SSE/Airtricity would fairly permanently be obligated each year, but below that, shares of Energia and Bord Gais Energy are very close; below that, there is a fairly significant gap before any other company might be considered. We now consider the case for applying an obligation to Energia and/or BGE based on market share. If only 3 MMO orders are to be placed in any year then both companies may face year-on-year changes in the requirement to be a MM.

A simple short term solution would be to apply the obligation to both because they are of similar size and the market would benefit from 4 rather than 3 MMs anyway. However, in a situation where there was a larger cluster of similar-sized businesses being considered for the last MMO order, a rule is needed to ensure a degree of year-on-year stability in the requirement to be an MM, given that there are costs in terms of trading functionality that need to be considered. Therefore, a stepped approach is proposed:

- **Step 1: Requirement for market makers.** If the market is already liquid then the need for MMs is diminished. This is a function mainly of market structure. The HHI calculated on the information on share of combined generation and supply shown in Table 9) is 2,455. Based on FERC's current guidelines on market concentration¹⁰, this is just below the highly concentrated level; a level below 1,500 would be considered unconcentrated according to FERC. If the HHI fell below 1,000 we would consider the market not requiring designated market makers provided that the share (generation plus supply) of the top 4 companies fell below 50%.
- **Step 2: De minimis level.** Some businesses will be too small to effectively offer MM services. There is no absolute methodology for selecting a

¹⁰ FERC uses the US Department of Justice & FTC's Horizontal Merger Guidelines: <https://www.ftc.gov/sites/default/files/attachments/merger-review/100819hmg.pdf>. This contrasts CEPA: Market Power and Liquidity in SEM, A report for the CER and the Utility Regulator, 2010, <http://www.cepa.co.uk/editordocs/file/CER%20SEM-10.pdf>, which sees unconcentrated below 1,000 and highly concentrated above 1,800.

threshold but 5% share of generation plus supply seems a reasonable proxy for financial strength (although, as noted above, a company with a strong financial position outside the electricity sector could always volunteer).

- **Step 3: Minimum number of MMs.** For reasons previously stated, at least 3 MMs would be required and so this is the minimum that would be obligated; Using data from 2015, four market participants would have a share of the combined market over 5%. The SEM Committee is of the view that the market share element has precedence over any arbitrary number of MMs. Hence four market makers should be designated (based on 2015 data). Year on year the RAs will review the list of designated MMs.
- **Step 4: Choice between 2 potential companies.** Where two companies of very similar size are in contention for the third market maker slot or (as is the case today in SEM) a fourth market maker slot then:
 - If company A is 10% larger than company B then company A should be chosen;
 - If company A is larger than company B by less than 10% then, if company B was a market maker in the preceding year, company B should be chosen ahead of company A because company B will have the infrastructure in place to continue in a market making role.

Quote obligations

Products

Price quotes should be available on the most viable forward products traded in SEM: baseload, mid-merit and peak. Therefore MMOs should be imposed on the following products:

- Baseload: 24 delivery hours per day, 7 days per week
- Mid-merit: 14 delivery hours per day (Mon-Fri 7am-9pm)
- Peak: 4 delivery hours per day (Mon-Fri 4pm-8pm)

Product delivery periods are quarter and month, with a trading period 12 months ahead of delivery period for all products. Granularity of product (standard contract size) is assumed to be 0.1 MW (like in NZ). This means that MMO volume can be allocated in MWs with 1 decimal place precision. This means that the minimum trade that a party can make with a MM is 100 kW per hour of delivery.

Time window

To meet the important objective of an MMO to “always have a price quote” there should be one market making window each business day of trading. In GB there are two market making windows per business day, however for the much smaller I-SEM market one market maker window per business day is judged sufficient. This single window should coincide with the second forward market making window in the GB market: 15h30-16h30.

MW obligation

Whereas GB has a rather large and identical MW obligation for each product (5+10 MW), MW obligations for MMs in NZ are more moderate and depend on product delivery period (3 MW for quarter baseload, 2 MW for month baseload). For I-SEM, the NZ approach is followed to have MW obligation per product where the size compares to the relative share of the product in the load curve.

- Baseload: 3.0 MW
- Mid-merit: 2.0 MW
- Peak: 1.0 MW

MW obligation holds during each market making window from start to end of the window, even if a quote is traded. This means that if a quote is traded, a re-quote must be provided that fulfils the MMO volume again. Prices are allowed to change with each re-quote. The quote/re-quote obligation holds until one of the caps is reached after which the obligation is suspended. Caps and corresponding suspension rules are specified below.

A quote is traded whenever any volume is bought or sold against the quoted price and does not require that the whole volume is taken. This means that a quote for baseload is traded even if the first buyer/seller trades only 100 kW with the MM; however, the MM is obligated to re-quote immediately.

Maximum price spread

A requirement to post both bids and offers and the use of a maximum spread provides an incentive to price products in a way that fairly reflects their market value. The price spreads for MMOs in GB are very tight. This is due to the fact that before the introduction of MMO price spreads were already tight (see Figure 17 in the Appendix) and churn was quite considerable (see Figure 16 in the Appendix). For the much smaller I-SEM market a price spread limit of 5% as applied in NZ seems more appropriate. Following the NZ experience, the actual price spread with multiple market makers (4 in NZ) is expected to be less than that.

Selection of Market Makers

While it is not an absolute requirement, VI businesses have the best capacity to cover risks in a 2-sided obligation. Using the 5% market share parameter: **ESB, SSE, BGE and Energia** are judged as the most suitable 4 market makers based on our criteria of sum of generation and supply as a proxy for size of balance sheet and ability to manage financial risk of prices moving against them.

Volume caps

A buy trade and a sell trade by one Market Maker would basically not contribute to coverage of the 13.2 TWh not covered by suppliers with shortage of VI generation. Therefore it makes no sense to put a cap on the volume traded. Instead a cap should be set on the net volume traded per Market Maker (according to his share in the MM volume) over a calendar period plus over a market maker trading window:

- **Over a given calendar period**, e.g. month and/or quarter and/or year, if the cap is reached, the MMO is suspended until the next calendar period. Note that if all MMs reach this cap during a given calendar period, there will be no guaranteed price quotes during the remainder of the calendar period.

As demonstrated above, with 250 windows per year, each market maker would have reached 1.69 TWh of trade with a 1 MW net trade position each market making window. Therefore a calendar year cap of 13.2 TWh net position traded would be reached when all market makers together reach an average net trade position of $\frac{13.2 \text{ TWh}}{1.69 \text{ TWh}} = 7.8 \text{ MW}$ per market making window across all products. This would mean, on 2015 shares with 4 MMs:

	Combined Volumes	Share of MMO
ESB	28,796,650	57%
SSE/Airtricity	10,371,548	20%
Energia	6,177,091	12%
Bord Gáis Energy	5,597,470	11%
	50,942,759	

Table 10: Shares of MMOs in the total

- **ESB** would be capped at $0.57 * 13.2 \text{ TWh} = 7.5 \text{ TWh}$ net traded volume a year, equivalent to $0.57 * 7.8 \text{ MW} = 4.4 \text{ MW}$ on average per MM window.
- **SSE** would be capped at $0.20 * 13.2 \text{ TWh} = 2.7 \text{ TWh}$ net traded volume a year, equivalent to $0.20 * 7.8 \text{ MW} = 1.6 \text{ MW}$ on average per MM window.

- **Energia** would be capped at $0.12 * 13.2 \text{ TWh} = 1.6 \text{ TWh}$ net traded volume a year, equivalent to $0.12 * 7.8 \text{ MW} = 1.0 \text{ MW}$ on average per MM window.
- **BGE** would be capped at $0.11 * 13.2 \text{ TWh} = 1.5 \text{ TWh}$ net traded volume a year, equivalent to $0.11 * 7.8 \text{ MW} = 0.9 \text{ MW}$ on average per MM window.
- **Per market making trading window per market maker:** if the cap is reached, the quote obligation is suspended until the next market making window. Such a cap still guarantees that there is a price quote available along the whole forward curve. The cap serves to limit the trading risks during a single market making window, caused by a fast increase of net traded volume. Quote obligation for the remainder of the market maker window would be suspended for a market maker if:
 - the net position traded during a market making window overall market makers would become 2 x total MMO obligation over all products and market makers, where each Market Maker gets a share in this cap relative to his overall MMO volume share e.g.:

Alternatively, a cap is imposed over a market making window only; In this case the cap should be a multiple of the equivalent average MW cap per MM to allow for some variations over a calendar period.

Price volatility cap

In addition, to cover for a fast change in prices traded during a market maker window, there should be (like in GB) a suspension of MMO per MM if:

- The price difference between a MM's first and last trade in the market making window is more than e.g. 4%; in this case quote obligation is suspended until the next market making window.

9 LIQUIDITY PROMOTION MEASURES – OPTIONS FOR CONSULTATION

9.1 INTRODUCTION

In this section we set out options for consultation. In all options, some form of Directed Contract will be retained. This means that a certain volume of Directed Contract will be determined by the current basic regulatory methodology; liquidity measures take these into account but are additional to the volumes offered under DCs. Similarly, the arrangements relating to generation sold under terms of the PSO will be retained in the same form as at present. This means that the volumes involved will be sold in auctions of CfDs at similar intervals to the present. The options are:

	Option1	Option 2	Option 3	Option 4	Option 5
	Clearing House and Exchange Trading or Tullet Prebon				
Direct contracts	Directed Contracts volumes determined as per current arrangements	Directed Contracts volumes determined as per current arrangements	Directed Contracts volumes determined as per current arrangements sold to non-ESB parties only	Directed Contracts volumes determined as per current arrangements sold to non-ESB parties only	Directed Contracts volumes determined as per current arrangements sold to non-ESB parties only
Ring-fencing	No Change in the current ring-fencing arrangements of ESB	No Change in the current ring-fencing arrangements of ESB	Integrated ESB GWM and Electric Ireland	Integrated ESB GWM and Electric Ireland	Integrated ESB GWM and Electric Ireland
Forward Contract Obligation	No Forward Contracting Obligation	Forward contract sell obligation on selected generators	Forward contract sell obligation on selected generators	Market Maker Obligation on selected companies (ESB, SSE, Energia and BG Energy)	Market Maker Obligation on selected companies (ESB, SSE, Energia and BG Energy) <i>Plus</i> Forward contract sell obligation on selected generators

Figure 8: Summary of options

Options for Consultation - Key Features

Option 1: Removal of Trading Barriers

One of the main barriers to trade is the cost of setting up bilateral trading arrangements and the collaterals that must be provided for each trade. By reducing the transaction costs of trading, market participants will be able to adjust their trading positions more easily.

This measure involves a trading platform, a central counterparty for trading and a central credit provider to allow multilateral trading and netting of collaterals. This is aimed at reducing the cost and other barriers to trading, thus facilitating liquidity.

The lack of trading mechanisms, including high levels of collateral, that market participants have identified as a significant barrier to trading will be addressed and will facilitate entry into the market. Publication of traded prices will increase confidence in pricing and so reduce trading risk. Option 1 involves the minimum intervention in the market. It maintains the current market incentives for forward contract trading, what we call today NDCs, would continue to be traded freely i.e. volumes and prices set by buyers and sellers along with cross border hedges available and internal hedges.

Option 2: Forward Contract Sell Obligation (FCSO)

In addition to the removal of barriers to trade described in the Option 1, This option addresses to an extent, a fundamental weakness of the current market, which is that generators have been unwilling to provide sufficient hedging products to meet the needs of suppliers. A mix of DCs, PSO auctions, FCSO volumes and access to cross border hedges for some volumes, will allow suppliers to find hedging products to cover their expected off-take. This option targets both concerns over market power and those best able to address possible market failure that is expressed by, and arises from, poor liquidity in the forward timeframe. Greater volumes setting the forward price compared to option 1 should lead to more robust forward pricing, thereby increasing the confidence in forward transactions, and enhancing overall liquidity.

Option 3: FCSO and Removal of ESB ring-fencing arrangements

This option builds on the removal of trading barriers discussed in Option 1 and introduces a FCSO on generators similarly to Option 2. This option also proposes the removal of ESB's ring-fencing arrangements. To offset the potential foreclosure of volumes available for trading caused by potential internalisation of hedging within the ESB group, this option proposes that ESB Generation should sell 90% of their

forecasted dispatchable volume compared to the 70% approximately under option 2. All other generators continue to offer contracts for 70% of their dispatchable volumes, as under option 2. In addition, DCs volumes that are currently allocated to Electric Ireland would be made available for other suppliers. The additional FCSO on ESB plus the re-allocation of DCs would increase substantially the volumes of hedging available to suppliers other than EI/ESB.

This could lead to an increase of approximately 3TWh traded at the forward market price (based on 2015 volumes), which in turn increases the robustness of the forward prices.

Option 4: Market Maker Obligation (MMO)

This Option introduces a Market Making Obligation on the largest market participants (ESB, SSE, Energia and BG Energy). It addresses two fundamental requirements of a liquid market: the ability of parties to easily trade out of positions taken and the offering of prices across the forward curve in trading that is essentially continuous. Given the two sided obligation (Buy and Sell) on market participants, this type of obligation is a more proportionate intervention measure if applied to vertically integrated entities; hence this option also proposes the removal of ESB's ring-fencing arrangements.

Option 5: MMO plus FCSO.

This option combines the feature of Options 3 and 4. The three key features of this option are: Introduction of FCSO, MMO and removal of ESB's ring-fencing. Volumes of FCSO and MMO are lower (50% lower) than the one assigned to the "pure" option 3 and 4 (Approximately 13 TWh are split 50/50 across FCSO and MMO). This option has a more sophisticated framework to promote liquidity in the market and although more complex to implement may present the most comprehensive response to the liquidity problem. This is because while MMO would provide prices continually, FCSO would concentrate liquidity in periodic auction. Hence these two mechanisms would complement each other giving the most effective answer to the issue being addressed.

Options for Consultation – Summary of Volumes Involved

The table below summarises the volumes of contracting obligation that will be assigned to market participants. These volumes have been calculated using 2015 data. For the actual obligations, forecast of generation should be used. Market participants would be free to trade CfDs volumes above to the volumes defined by FCSO or MMO

	Option 1 TWh	Option 2 TWh	Option 3 TWh	Option 4 TWh	Option 5 TWh
<i>(Non-dispatchable generation)</i>	7.64	7.64	7.64	7.64	7.64
Dispatchable Generation 2015	24.20	24.20	24.20	24.20	24.20
Sources of Hedge					
DCs	3.90	3.90	3.90	3.90	3.90
PSOs	2.48	2.48	2.48	2.48	2.48
FCSO	0.00	10.07	12.99	0.00	6.50
MMO	0.00	0.00	0.00	13.20	6.61
NDCs*	4.80				
Total Hedging Volumes excluding internal hedges and cross border hedges	11.18	16.45	19.37	19.58	19.48
Generation not under externally traded obligation	13.02	7.75	4.83	4.62	4.72
% of disp. gen. under obligation	53%	68%	80%	81%	81%
% of demand covered by FCO	31%	47%	55%	55%	55%

*2015 volumes of NDCs have been included under Option 1 just to help the comparison between options, it should be assumed the a substantial part of volumes covered by NDCs today will be absorbed by either FCSO or MMO under the other options.

Options 3 to 5 involve the removal of ESB's ring-fencing and as an additional feature, Electric Ireland would no longer receive allocation of DCs, hence the rest of suppliers would be offered DCs volumes which today are allocated to EI. This would apply under either of the allocation vs. auction approaches discussed under section 4 In 2015 Electric Ireland's share of DCs were 1.597 TWh. This volume should also be taken in consideration by market participants when assessing the options above.

The remaining sections will give further detail on how these options have been designed; it builds on analysis presented from Section 6 to 8.

9.2 OPTION 1: REMOVAL OF TRADING BARRIERS

Option 1 is the least intrusive of the options other than DCs on ESB to mitigate spot market power. It imposes little if anything in terms of new obligations on market participants; indeed it may reduce the level of existing impediments to trading and this is its purpose. It is the least interventionist of the options and does not require the identification of one set of participants who are treated (with specific obligations) as being different from another set of participants (who have no such obligations). Option 1 would involve some administrative cost in terms of setting up cost and on-going operations, as do other options. It is justified as an option for consideration because it delivers potential for an incremental improvement upon the status quo. Exchange traded NDCs reduce cost of trading and barriers to entry for non-VI generators that today may not offer NDCs because of the cost of agreeing bilateral arrangements with multiple counterparties., Option 1 represents a path towards improved market efficiency with relatively little upheaval. (Refer to section 3: Identifying the Issues in the Forward Market, and especially sections 3.1 and 3.2 which show that more than 70% of the market is effectively hedged forward today, for a discussion on this point.) Option 1 focuses efforts only on the introduction of new mediums to trade as described in Section 6.

The characteristics of this option are such that little will change in relation to forward contracting obligations:

- DCs – Volumes will continue to be determined by the RAs.
- PSO generation would continue to be auctioned as CFDs for as long as such contractual arrangements continue.
- NDCs may voluntarily continue to be offered as well as OTC hedging arrangements.
- Ring-fencing arrangements will not change.

This does not preclude a replacement of the current Tullett Prebon services by other providers including potential new clearing and collateral providers. It also does not preclude interest by generators in offering more hedging products, which should naturally occur because the cost-based pool is being replaced by a DAM in which some fixed costs will be incorporated into the price.

In other words, this option relies on a greater willingness of all participants to trade forward due to changes in the underlying reference price derived from the DAM relative to the existing pool-based reference price, and on potential new trading services being offered to the market. In relation to current arrangements for forward trading, the only change would be the possible introduction of new mediums to trade as described in the section 6.

As the market structure develops, the volume of DCs that ESB will be obliged to offer on the current formula will diminish, and the PSO requirement is similarly diminishing. Therefore, an increased reliance on NDCs will be a feature of this market. Clearly, such a situation would need to be monitored. Finally the absence of mandated volumes of FCSOs, volumes traded should be lower; hence forward price may be less robust, which may impact negatively on liquidity.

It should also be noted that the reliance on voluntary provision of new services may be contingent on assessment of the adequacy of trading volumes to be expected in the market. The introduction of a central trading platform, to the extent that it is underpinned by guaranteed trading volumes may, in fact, be facilitated by the introduction of the regulatory interventions discussed in subsequent options.

In relation to DCs price formation discussed in section 4, this option would probably work better with the RAs determining prices administratively instead of a market based mechanism. This is in keeping with the spirit of this option which is minimal change to the current arrangements. It is also the case that given the levels of concentration in the suppliers' market, within an auction based mechanism, there would be an undue upward pressure on the on the DCs prices diminishing the effectiveness of this instrument to mitigate market power in the spot market.

9.3 OPTION 2: FORWARD CONTRACT SELL OBLIGATION (FCSO)

This option introduces a FCSO on certain generation companies which are above a certain market share of dispatchable volumes. These companies would have an obligation to offer forward CfDs for certain standardised contracts. These would be offered into auctions to coincide with DC allocations or with PSO auctions with the RAs setting the reserve price.

Option 2 is considered because it ensures minimum levels of forward contracts are made available for sale (albeit at a minimum price). It thus addresses the liquidity issue administratively, centrally determining: the minimum quantities that must be offered, and the minimum prices at which they must be offered. The identity of the specific participants who must offer contracts is also determined by an administrative rule. Option 2 rests on a premise that there is a problem, or market failure, and that the market, even with the removal of trading barriers will not solve this problem by itself. Option 2 involves new obligations, risks and opportunities for some market participants.

The key terms of an FCSO are set out in Section 7. The obligation is proportionate to the ability to solve the problem. The analysis of section 7 was based on 2015 MSQ data. For an actual scheme, the forward looking expectations of dispatch would need to be modelled to assess the extent to which each company ought to be asked to contribute.

FCSO requirement and minimum threshold for provision

Based on the analysis in Section 7, an FCSO of 16.45 TWh would have been introduced based on 2015 data. A minimum threshold below which nothing need be offered is also described in Section 7, which offers a pragmatic basis for exclusion of the smallest companies from the scheme. On this basis, the equivalent of the results in Table 11, based on 2015 MSQ could apply:

	MSQ 2015 (TWh)	Share	Gross FCSO	DCs	PSO	Net FCSO
ESB	14.62	61.33%	10.09	3.9	2.48	3.71
Bord Gais	2.59	10.88%	1.79			1.79
AES	1.68	7.06%	1.16			1.16
Aughinish	1.34	5.61%	0.92			0.92
Tynagh	1.26	5.31%	0.87			0.87
SSE	1.22	5.12%	0.84			0.84
Bord na Mona	0.81	3.41%	0.56			0.56
PPB	0.31	1.29%	0.21			0.21
Grand Total	23.84	100%	16.45			10.07

* Net FCSO excludes DC and PSO volumes which for 2015 were 3.9 TWh and 2.48 TWh respectively

Table 11: allocation of FCSO to generating companies

Figure 10 illustrates the stages for determination of a cap on the FCSO and its respective allocation to generation companies (based on market data from 2015). As discussed on section 7, 50% of the forecasted demand for hedging should be met by external hedges from generation companies. The obligation on each generator would be proportional to its forecasted market share of dispatchable generation (Gross FCSO). ESB could meet part of its obligation with DCs and PSO volumes (Net FCSO).

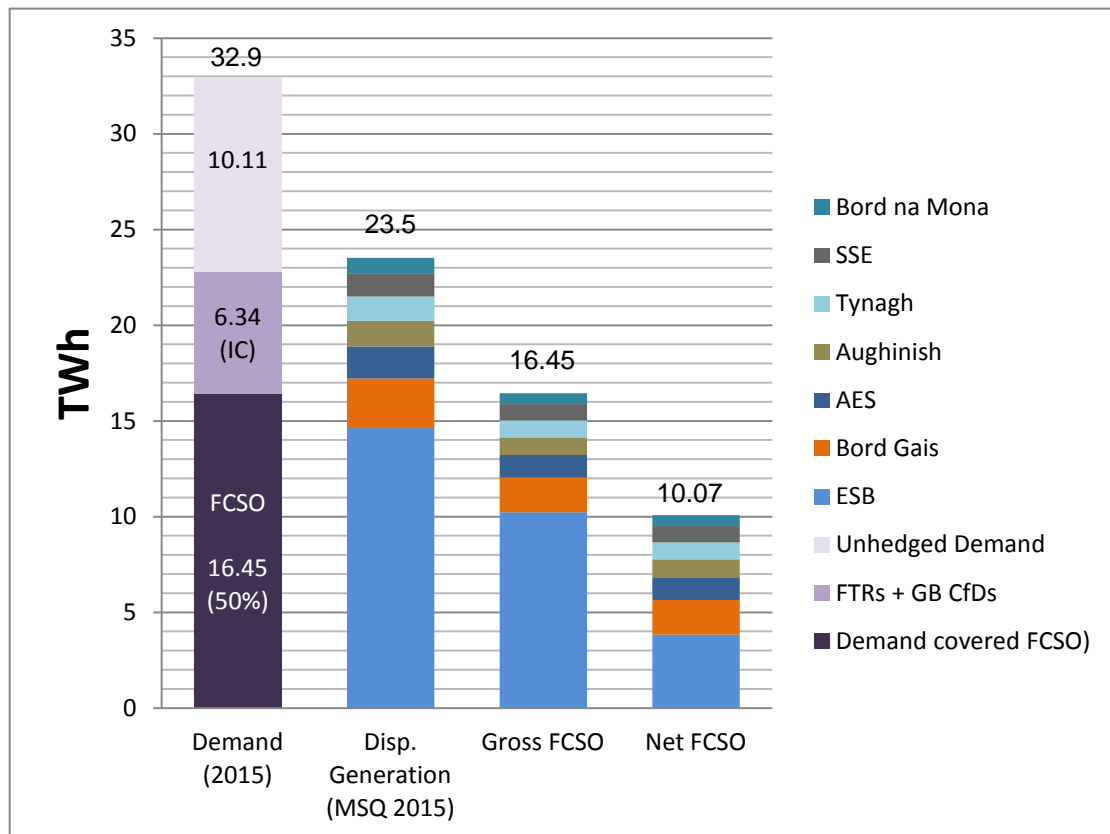


Figure 9: Illustration of sources and purchases of FCSOs

Based on 2015 data and assuming that the outcome of FCSO auctions allocate volumes, DCs and Non DC FCSOs awarded in the same proportions to the market share of each supplier, we would have the distribution of volumes between suppliers shown in Table 12:

	Market Share	Potential Allocation of FCSO (TWh)
Electric Ireland	37.7%	6.21
SSE Airtricity	22.0%	3.61
Energia	14.2%	2.33
Power NI	8.6%	1.41
Bord Gáis Energy	8.0%	1.31
LCC/Go Power	3.3%	0.54
Others	3.2%	0.53
Vayu	1.2%	0.20
PrePayPower	1.2%	0.19
Budget Energy	0.7%	0.11
Firmus	0.1%	0.01
Total	100%	16.45

Table 12: Allocation of FCSOs proportional to market share of supplier

Generation companies that have historically not sold forward contracts or sold in low volumes will now be required to do so. Additional volumes (10.07 TWh compared to 4.8TWh under option 1) mean that a more robust price for forwards would be determined when compared to option 1. This means that additional liquidity would be forthcoming in addition to the mandated volumes.

As discussed under option 1, given the levels of concentration in the suppliers market, the SEM Committee is of the view that this option would work better with the current administrative process to determine DC prices.

9.4 OPTION 3: FCSO AND REMOVAL OF RING-FENCING ARRANGEMENTS

This option is a variation of Option 2. It would involve the introduction of a FCSO on the same lines as Option 2. Generator would be required to provide an aggregate volume of yearly forward hedge of 16.45 TWh. However the ring-fencing arrangement between the ESB Generation and Supply businesses would be removed, as well as a change in the methodology for allocation DC volumes.

Option 3 is justified as a separate option for consideration on the basis that the removal of the ring-fencing arrangement would change the volumes of FCSO that ESB would be obliged to sell and change the allocation of the DC related volumes. Figure 11 represents the market structure which would have been materialised in 2015 under a scenario where ESB’s ring-fencing arrangement is removed.

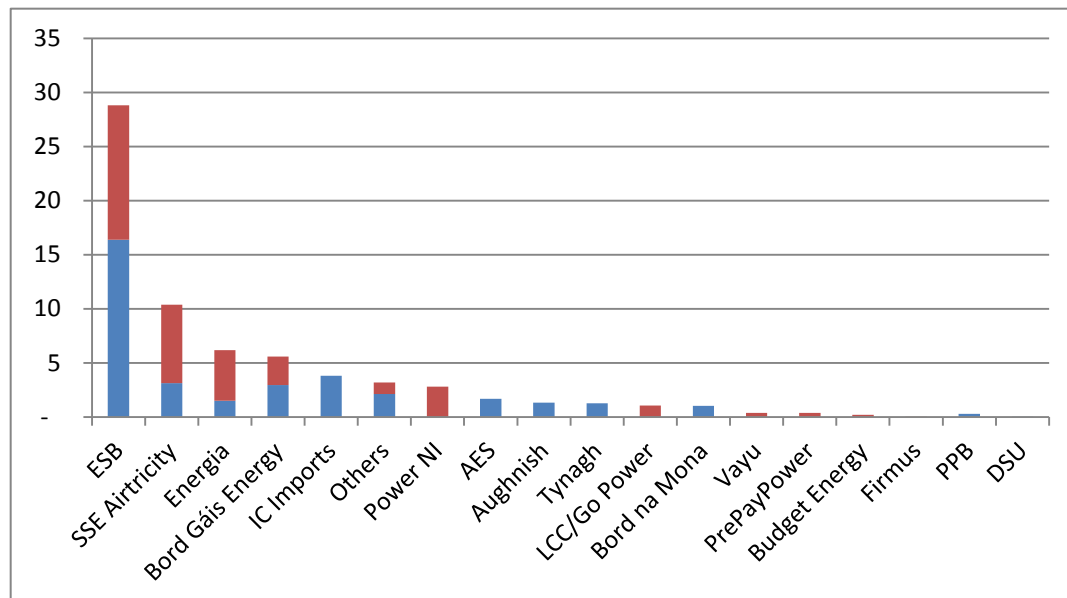


Figure 10: Market structure without ring-fencing

In order to avoid a substantial share of the forward market being internalised by ESB, if they were vertically integrated, an additional volume of FCSO would be required. Given the substantial share of the generation and supply market that would be covered by ESB, the SEMC proposes that ESB should sell in the forward market to third parties its entire dispatchable generation. In order to cater for any unforeseen outages, **[90%]** of ESB forecasted (dispatchable) generation should form part of a FCSO.

The table below shows ESB’s generation by fuel type in 2015.

	MSQ TWh
GAS	6.9
COAL	5.7
PEAT	1.7
WIND	1.0
HYDRO	0.7
PUMP	0.1
Grand Total	16.3

By excluding wind and hydro generation, ESB’s dispatchable generation was 14.6 TWh in 2015. 90% of this volume should form part of a FCSO. Hence ESB FCSO would be 13.14 TWh. The increase in ESB’s obligation would not reduce the FCSO applying to other generators.

Therefore all generators would have a FCSO volume of 16.45 TWh multiplied by its FCSO share (market share above the de minimis level). ESB volume would be calculated as follows:

$$ESB_{FCSO} = \max[(ESB_{DispGen} * 90\%), (16.45 TWh * ESB_{GenShare})]$$

Using data from 2015,

$$ESB_{FCSO} = \max[(14.6 TWh * 90\%), (16.45 TWh * 62.13\%)] = 13.14 TWh$$

Hence, ESB would be required to sell 13.14 TWh instead of 10.09 TWh under Option 2 and 6.38 TWh under option 1 (based on 2015 data). Table 13 shows the volumes of obligation that would be set for generators.

	Gross FCSO	Net FCSO
ESB	13.14	6.76
Bord Gais	1.81	1.81
AES	1.18	1.18
Aughinish	0.94	0.94
Tynagh	0.88	0.88
SSE	0.85	0.85
Bord na Mona	0.57	0.57
Grand Total	19.37	12.99

*Net FCSO excludes DC and PSO volumes which for 2015 were 3.9 TWh and 2.48 TWh respectively

Table 13: FCSO without ring-fencing

ESB would still be required to offer volumes of DCs determined by the RAs (based on generation market share). However, Electric Ireland would no longer get an allocation (or be able to bid for DCs). This is because the removal of ring-fencing would make it difficult to disassociate market power in the demand or generation

side of ESB. Having DCs allocation to Electric Ireland could water down the incentives of ESB generation to bid competitively in the spot market as CfDs payments would be largely internalised.

	Market Share	Potential Allocation of FCSO	Net Allocation*
Electric Ireland	37.7%	7.32	5.72
SSE Airtricity	22.0%	4.26	4.82
Energia	14.2%	2.75	3.11
Power NI	8.6%	1.66	1.88
Bord Gáis Energy	7.8%	1.55	1.75
LCC/Go Power	3.3%	0.64	0.72
Others	3.2%	0.62	0.70
Vayu	1.2%	0.23	0.26
PrePayPower	1.2%	0.23	0.26
Budget Energy	0.7%	0.13	0.15
Firmus	0.1%	0.01	0.01
	100.0%	19.39	19.39

* Net Allocation removes the DCs volumes from Electric Ireland and re-allocate to other suppliers proportionally to their market share. PSO generation would be auctioned in the same way as present

Table 14: Allocation of FCSOs without ring-fencing

In relation to the mechanism for determination of DC Prices, the SEM Committee is of the view that this option would work better alongside a market based mechanism for determination of DCs prices. This is because Electric Ireland, which is the largest supplier by a significant margin, would no longer exert an upward pressure on the price formation. An auction based mechanism would also aid promotion of liquidity in the market by increasing the volumes being auctioned to the industry.

9.5 OPTION 4: MARKET MAKER OBLIGATION

This option would introduce a market maker obligation on certain market participants. The nature of market making is that it is a two-sided business, with prices necessarily quoted for both buy and for sell. The RAs should determine the volumes of obligation on an annual basis and although prices should be determined via market based mechanisms, the RAs would regulate the spread between buy and sell prices.

Like Option 2 and Option 3, Option 4 is justified as an option for consideration because it ensures forward contracts are made available for sale. It does not specify a minimum price, but rather a minimum price *spread*. Like Option 2 and Option 3 it addresses the liquidity issue administratively: the identity of the specific participants who must offer contracts and their maximum price spread are determined by an administrative rule. Option 4 again rests on a premise that there is a problem, or market failure, that needs to be solved administratively and that, even with the removal of trading barriers, the problem will not be resolved. Option 4 involves new obligations, risks and opportunities for some market participants, albeit these are different to those under Option 2 and Option 3. Option 4 is also justified as an option for consideration because, significantly, there is some international precedent for similar methodologies – most notably Great Britain and New Zealand, albeit these markets might have been motivated to implement their methodologies by slightly different factors.

Vertical integration, even if not absolutely necessary, would strengthen the capacity of the market maker to offer volumes as the key requirement is financial strength of the company to take on a market maker risk. In this context, the SEM Committee is of the view that in order to implement this option, ESB's ring-fencing arrangements should be removed. In this arrangement, DCs volumes would continue to be calculated by the RAs and allocated as described under Option 3 (i.e. Electric Ireland would not receive an allocation of DCs).

Based on the parameters of the market discussed in Section 8, which used data from 2015 as an example, the total MMO could be capped at 13.2 TWh per year. For the actual obligation, the volumes should be calculated by forecasting the total net exposure of all vertically integrated and independent suppliers. Figure 12 shows the net exposures (generation minus demand in the case of VIs) of each market participant in 2015.

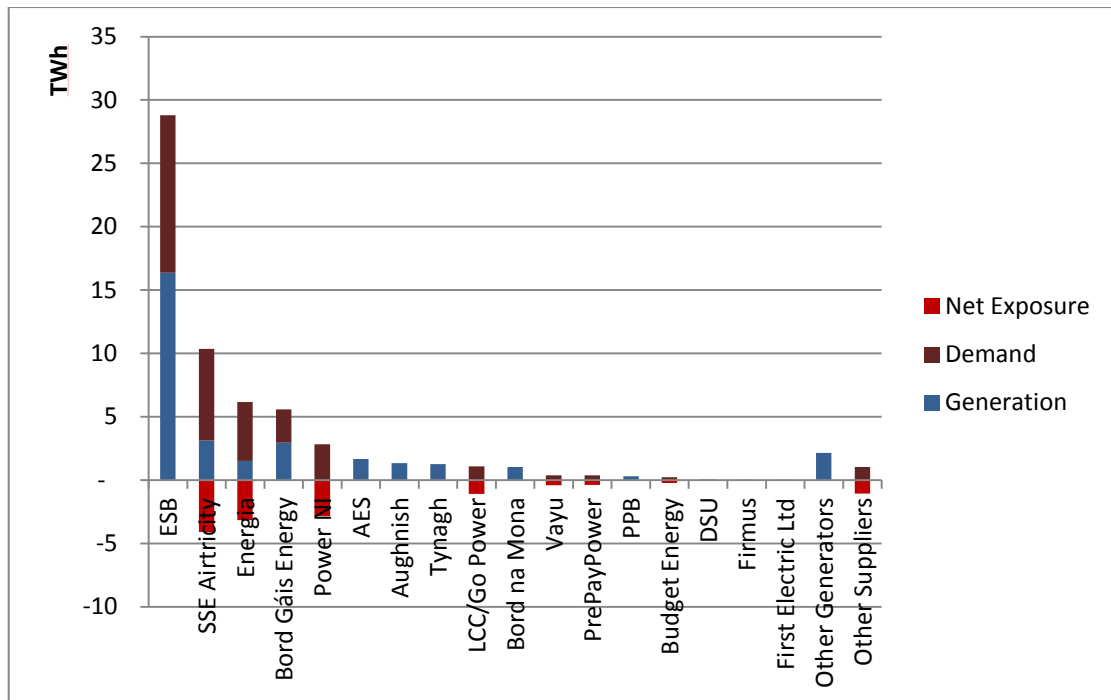


Figure 11: Net exposure of market participants in 2015

The total net exposure illustrated above, have the distribution among suppliers shown in Figure 13.

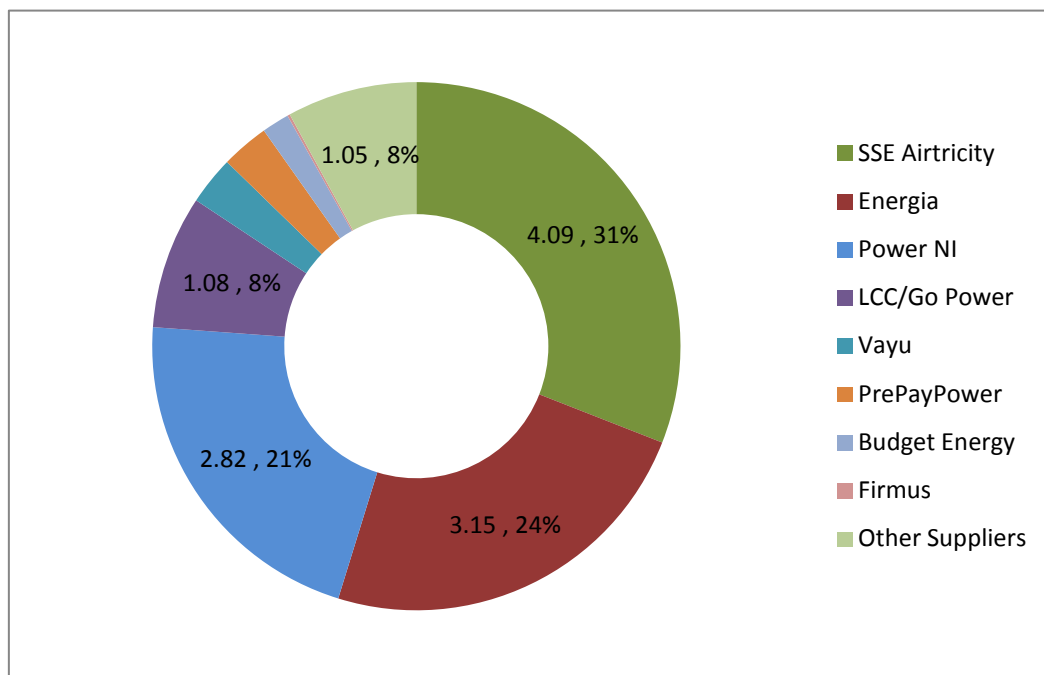


Figure 12: Distribution of net exposures of suppliers, 2015

In order to determine the level of obligation applying to each market maker, the following steps are followed:

- The first stage establishes the combined volumes of generation and supply of the four largest four (vertically integrated) entities (Assuming the ESB ring-

fencing arrangements are removed), this stage determines the share of capped volumes that would be assigned to each market maker.

- Subsequently, the level of overall market exposure is determined by netting off generation and supply in the market.
- Finally the volumes of obligation are distributed to each market maker proportionally to its share in the combined market.

Figure 14 illustrates the different stages of the allocation process.

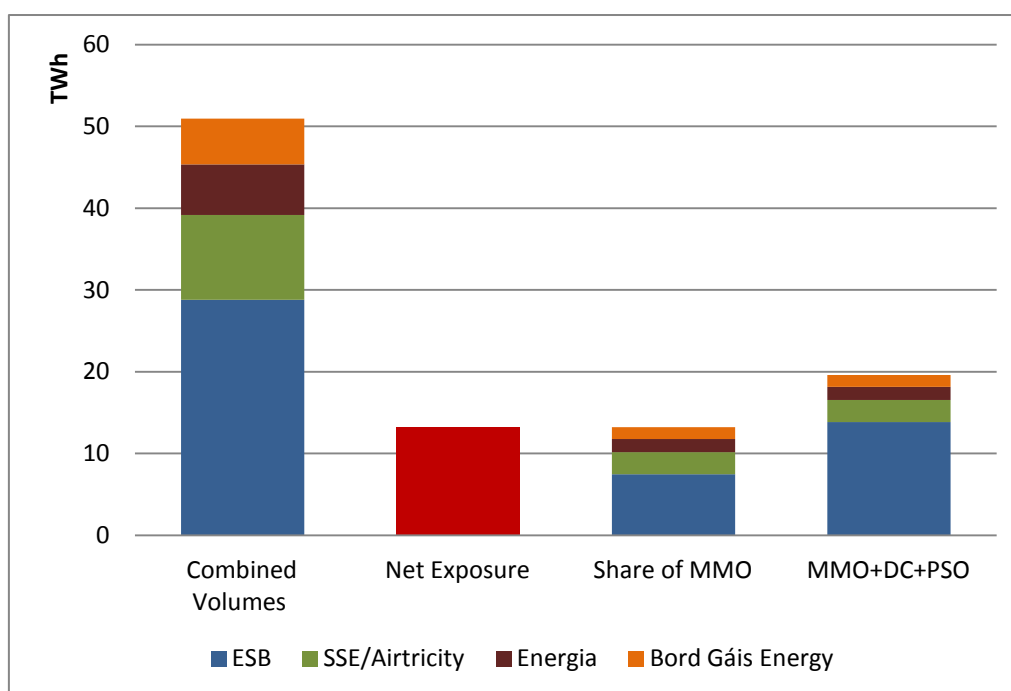


Figure 13: Market making obligation allocation process

Building on that earlier analysis, the MMO capped annual obligation would be:

- **ESB** would be capped at $0.57 * 13.2 \text{ TWh} = 7.5 \text{ TWh}$ net traded volume a year, equivalent to $0.57 * 7.8 \text{ MW} = 4.4 \text{ MW}$ on average per MM window.
- **SSE** would be capped at $0.20 * 13.2 \text{ TWh} = 2.7 \text{ TWh}$ net traded volume a year, equivalent to $0.20 * 7.8 \text{ MW} = 1.6 \text{ MW}$ on average per MM window.
- **Energia** would be capped at $0.12 * 13.2 \text{ TWh} = 1.6 \text{ TWh}$ net traded volume a year, equivalent to $0.12 * 7.8 \text{ MW} = 1.0 \text{ MW}$ on average per MM window.
- **BGE** would be capped at $0.11 * 13.2 \text{ TWh} = 1.5 \text{ TWh}$ net traded volume a year, equivalent to $0.11 * 7.8 \text{ MW} = 0.9 \text{ MW}$ on average per MM window.

Table 15 shows the volumes of potential allocation of volumes based on market share of each supplier.

	Market Share	Potential Allocation of MMO	Net Acquisition by supplier
Electric Ireland	37.7%	7.40	5.80
SSE Airtricity	22.0%	4.31	4.87
Energia	14.2%	2.78	3.14
Power NI	8.6%	1.68	1.90
BGE	8.0%	1.56	1.77
LCC/Go Power	3.3%	0.64	0.73
Others	3.2%	0.63	0.71
Vayu	1.2%	0.23	0.26
PrePayPower	1.2%	0.23	0.26
Budget Energy	0.7%	0.13	0.15
Firmus	0.1%	0.01	0.01
	100.0%	19.60	19.60

* DCs and PSOs volumes have been added to the volumes available for hedging (based on 2015 data 3.9 TWh plus 2.48 TWh respectively, 13.2 + 3.9 + 2.48 = 19.6). Net Allocation removes the DCs volumes from Electric Ireland and re-allocate to other suppliers proportionally to their market share

Table 15: Potential allocation of MMO contracts by supplier

Market making is also partly reliant on provision of a trading platform to ensure visibility of prices offered as well as on efficient clearing of the market. After all, with voluntary MM services, the attraction of cheaper trading fees on established platforms is the primary incentive for parties to offer the service – without a platform there would be an obligation without a corresponding benefit.

The primary focus of MMO is to promote robust price formation given the continuous availability of posted prices. MMO differs from FCSO to the extent that the RAs don't set reserve prices, RAs would only set the spread between posted prices to buy and sell.

In relation to the mechanism for determination of DC Prices, the SEM Committee is of the view that this option would work better alongside a market based mechanism for determination of DCs prices. This is because Electric Ireland, which is the largest supplier by a significant margin, would no longer exert an upward pressure on the price formation. An auction based mechanism would also aid promotion of liquidity in the market by increasing the volumes being auctioned to the industry.

9.6 OPTION 5: MMO PLUS FCSO

This is a hybrid derived from Options 3 and 4. There would be no ring-fencing and the rules for DC and PSO allocation/sale would be the same as in Option 3.

The FCSO would be for smaller volumes than would be the case with Option 3.

Similarly, the capped exposure to MMOs would be scaled down to reflect the greater underlying volume of products already in the market due to the FCSO.

This hybrid option is justified for consideration because, while the MMO from option 4 would provide market access and price discovery in the forward market, it would not necessarily provide sufficient volume of hedging contracts to meet market participant expectations unless the MMOs were exposed to an extent which they may consider excessive.

The steps of this option would be as follows:

- Remove ring-fencing
- Determine DCs and PSO volumes and allocate the former as per Option 3, ESB's Net FCSO will be adjusted to remove any volumes sold under DC and PSO obligation.
- Determine the volume of FCSO to be applied as per Option 3:
 - The exemptions due to size would remain the same – those with less than a volume such that about 533 GWh would be exempt:
 - Apply a lower limit to the FCSO (50% of Option 3).

	Gross FCSO	Net FCSO
ESB	6.57	3.38
Bord Gais	0.91	0.91
AES	0.59	0.59
Aughinish	0.47	0.47
Tynagh	0.44	0.44
SSE	0.43	0.43
Bord na Mona	0.29	0.29
Grand Total	9.685	6.495

* Net Allocation removes the DCs volumes from Electric Ireland and re-allocate to other suppliers proportionally to their market share

- For the residual non-voluntary element of the MM requirement, apply a MMO in line with Section 8, but with the exposure caps set out in Option 4 reduced to reflect the obligations arising from FCSO.

- MMO = (50% of Option 4 = $13.2/2 = 6.6$ TWh) and then allocate it as per Option 4:
- Average net trade position of $\frac{6.6 \text{ TWh}}{1.69 \text{ TWh}} = 3.9 \text{ MW}$
 - **ESB** would be capped at $0.57 * 6.6 \text{ TWh} = 3.7 \text{ TWh}$ net traded volume a year, equivalent to $0.57 * 3.9 \text{ MW} = 4.4 \text{ MW}$ on average per MM window.
 - **SSE** would be capped at $0.20 * 6.6 \text{ TWh} = 1.3 \text{ TWh}$ net traded volume a year, equivalent to $0.20 * 3.9 \text{ MW} = 0.78 \text{ MW}$ on average per MM window.
 - **Energia** would be capped at $0.12 * 6.6 \text{ TWh} = 0.79 \text{ TWh}$ net traded volume a year, equivalent to $0.12 * 3.9 \text{ MW} = 0.46 \text{ MW}$ on average per MM window.
 - **BGE** would be capped at $0.11 * 6.6 \text{ TWh} = 0.72 \text{ TWh}$ net traded volume a year, equivalent to $0.11 * 3.9 \text{ MW} = 0.42 \text{ MW}$ on average per MM window.

With regard to exposure caps, it should be noted that an FCSO applies an identical exposure to a sell by an MMO in that a CfD is created with a strike price that may be, on average, above the DAM reference price – this price premium would reflect the underlying structural shortage of dispatchable generation, with FCSOs unlikely to fully meet suppliers' desire to hold hedging instruments – this is an exposure especially to parties who are short of generation. However, the MMO becomes a useful corrective to any inflation of the strike price from FCSO auctions in that those MMOs will have an interest in offering to buy CfDs with a lower strike price because they will be short on generation themselves and so will not want the price to be high.

It should be noted that the FCSO is calculated based on dispatchable generation whereas the MMO caps are based on gross position in the market in all generation and supply less obligations to sell hedging products. This is because, for the FCSO, there is a fixed obligation, which generators are expected to back off using physical assets whereas for the MMO, the parties are expected to manage their positions and their capacity to do so is based on their market throughput, which includes non-dispatchable generation as well as dispatchable generation and supply.

The volume of obligation associated with this option is about the same as option 3 and 4. Non-dC volumes are split across FCSO and MMO. The RAs would set the reserve price for FCSO and the spread of MMO. While the FCSO would lead to an

obligation for designated parties to contract, the MMO would create the obligation to post prices for buy and sell CfDs.

In relation to the mechanism for determination of DC Prices, the SEM Committee is of the view that this option would work better alongside a market based mechanism for determination of DCs prices. This is because Electric Ireland, which is the largest supplier by a significant margin, would no longer exert an upward pressure on the price formation. An auction based mechanism would also aid promotion of liquidity in the market by increasing the volumes being auctioned to the industry.

10 INITIAL ASSESSMENT OF OPTIONS

In discussing the options available in Section 9, we are using the following criteria to assess whether the option is viable. The criteria are:

- **Effective:** the proposed measure should be effective in facilitating development of liquidity, either directly or as an outcome of encouraged behaviours.
- **Targeted:** the proposed measure should interfere with the operation of the market to the minimum extent necessary, aimed at those best in a position to facilitate greater liquidity.
- **Flexible:** the measure should be sufficiently flexible and robust to account for changes in market fundamentals and changes to the generation and supply mix. Flexible also implies the ability to remove the measure should it no longer be required.
- **Practical:** the measure should allow the RAs to have readily understood, predictable and reasonable administrative processes to implement the mitigation measure and facilitate enforcement in a short timeframe. The measure should also be cost effective and should be implementable within the scope of the regulatory framework.
- **Transparent:** compliance should be easily achievable and transparent for all existing and potential participants to view.

Option 1 scores poorly on effectiveness as it does not address the asymmetry of incentives for forward trading between generators and suppliers. Options involving FCSO (2, 3 and 5) address directly the issue of lack of available products, while option 4 MMO-only focuses on price availability.

While Option 1 is the minimal intervention in the market, it does not target those best able to provide forward hedges. Options 2 to 5 places obligations proportionately on those best able to discharge them.

Option 1 does not place an obligation of forward trading on any market participant while the introduction of subsequent measures would involve a new policy development process. Option 2 is the most flexible. Options 3 to 5 would involve market re-structuring (ESB) and is therefore less flexible.

Options 1 and 2 are comparatively less demanding in terms of resources and control mechanisms (practicality). Options 3 to 5 involve removal of ESB ring-fencing, which introduces new market monitoring mechanisms. MMO based options are also more complicated to regulate.

Option 1 maintains the current forward trading arrangements which have been deemed to be sub-optimal from the transparency stand point i.e. DCs is very transparent. Options 2 to 5 introduce regulated volumes to be traded in public auctions or transparent platforms for continuous trading.

The above assessment presents the SEM Committee initial views on how well the different options perform against each evaluation criteria. This initial assessment is indicative only and for the final decision, responses from market participants will be instrumental to reinforce or change the SEM Committee's views on the performance of each option.

11 IMPLEMENTATION ISSUES

11.1 LICENSE CHANGE AND COMPLIANCE MONITORING

Obligations placed on market participants will be implemented through licence conditions on the obligated parties, which shall be drafted on the basis of the final Decision Paper in the Forward and Liquidity workstream, scheduled for publication in September 2016. Responsibility for drafting the text of the licence conditions will be devolved to the Governance and Licensing workstream which shall consult upon the licence changes arising from the Forward and Liquidity and other workstreams. The licence condition will allow the obligated parties to consider the specific scope and nature of the legal obligations arising from the policy decisions. This will not only provide clarity on the obligations themselves but also the arrangements for their introduction, including timescales involved, and regular reporting on compliance with the obligation.

The reporting arrangements placed on licensees will be the primary means by which the Regulatory Authorities will ensure that obligations are appropriately discharged. Such reporting arrangements will be proportionate and shall be sufficient to ensure appropriate and effective operation of licence requirements. This shall include a statement by the licensee that it has complied or has not complied (giving reason for non-compliance) with the licence condition over the relevant period.

The RAs will review the continued application of the licence condition at relevant times, taking account of the experience of the operation of the licence condition and its effectiveness in achieving the policy objectives of the Forward and Liquidity Decision Paper. When considering the continued appropriateness and scope of any obligation on market participants the RAs will consider a number of factors including the views of licensees and other market participants and the proportionality of their licence obligation. The factors considered will include a non-exhaustive set that will include the circumstances of the licensee and the development of the I-SEM.

The RAs will therefore consider all the relevant circumstances of the market participant and the market taken as a whole, including new entry. This may result in amendment or removal of the licence condition on particular market participants and/or obligations placed on other market participants. The RAs will not seek to make changes to obligations unless sustained and significant changes occur in the circumstances of licensees and/or the market. This does not fetter or limit reconsideration by the SEM Committee of the appropriateness of the policy decisions taken to promote liquidity in the forward market and the measures determined primarily by market power concerns. Any changes to policy considered

necessary from such review shall of course be subject to full consultation with market participants.

Market participants shall remain free to seek removal or amendment of obligations from the license by written request to the Regulatory Authorities with full argumentation and supporting evidence. Such requests will receive the full consideration of the RAs taking account of the issues set out above. It is therefore considered that such requests will involve provision of evidence of sustained and significant changes having occurred in the circumstances of the licensee and/or the market.

11.2 ROADMAP FOR IMPLEMENTATION INCLUDING TRANSITORY ARRANGEMENTS

With I-SEM go-live in Q4 2017, trading of forwards with I-SEM reference prices should start by the end of Q1 2017. Any later start would require interim arrangements for any anticipated FCSOs and MMOs.

Power derivatives futures markets usually develop organically after maturing of the reference market. Would this also be the case for I-SEM, this may require a transitory arrangement for forward contracting obligations to go live by the end of Q1 2017.

Transitory arrangement

FCSOs may be auctioned under similar rules as today's PSOs but with more suppliers and potentially without a reserve price. MMOs may be facilitated on the current OTC continuous trading platform as Tullett Prebon is also facilitating MMOs in the GB forwards market. If decided to be auctioned, current Tullett Prebon auction rules may allow for auctioning of DCs with reserve prices like the PSOs. Combination of auctioning of DCs with PSOs and FCSOs may require development of new auction rules which may impose a longer time to implement.

Altogether the following high level project planning milestones are foreseen:

On I-SEM

- Decision on forwards liquidity intervention: September 2016
- I-SEM DAM maturity date (earliest date on which a futures market could start organically, not displayed in GANTT)

On target solution for forward auctioning and continuous trading

- Detailed design, including parameters mentioned in section 11.3
- Auction implementation (IT, rules, regulations)
- Market trials
- Go-live

On interim solution for forward auctioning and continuous trade

- Decision on need for interim solution

RAs are currently and in parallel to the consultation seeking engagement for voluntary provision of the target solution with potential providers. Should this lead to an expected implementation time beyond April 2017, a decision on an interim arrangement will be required, which may be based on the following elements:

- Continuation of current mechanism for DCs but with I-SEM DAM as reference price
- Auctioning of FCSOs, based on the same rules as for today's PSO auction but with more than one CfD supplier and potentially without a reserve price
- Introduction of MMOs in current NDC trading
- Design, implementation and market trials of interim solution
- Go-live of interim solution. The following elements of an interim solution will move to the target solution as soon as available (if these are decided as interventions for the I-SEM forward market):
 - DC auctioning
 - FCSO auctioning, possibly together with DC auctioning
 - MMO continuous trading
- Decided intervention measures will move from interim to target solution as soon as available.

On licensing:

- The Consultation Paper on Licence changes relative to Forwards and Liquidity should be published by September 2016
- Responses should be submitted by end of November 2016
- Licence changes should be published by February 2016

An indicative roadmap is shown in the picture below.

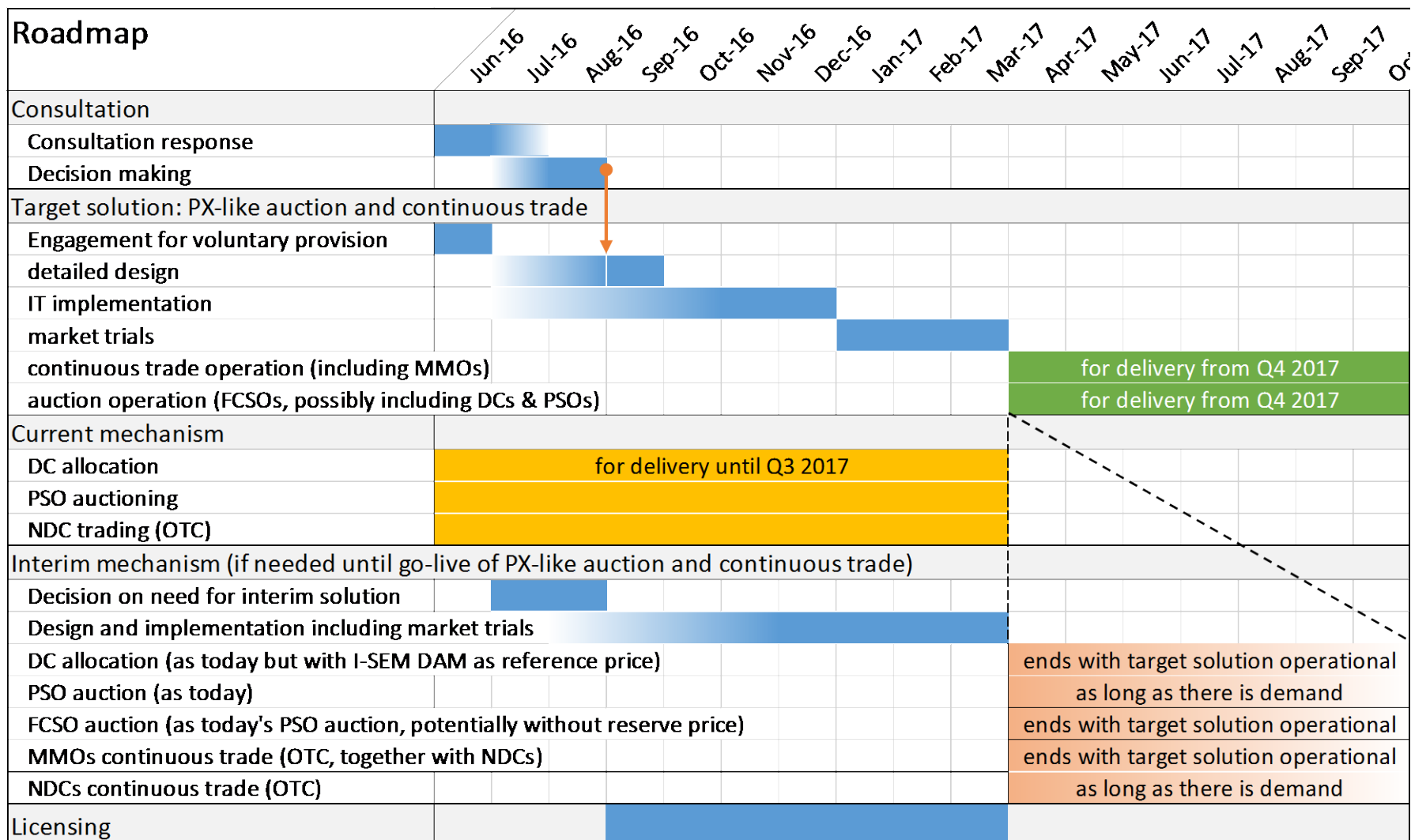


Figure 14: Potential implementation timeline

11.3 DESIGN PARAMETERS NOT IN SCOPE OF DECISION

Throughout this paper worked examples on several design parameters were chosen which are not in scope of decision for this consultation. These will be decided later in close cooperation with the service providers and the market. Nevertheless, opinions on these parameters are appreciated.

The following parameters on auction design and product design are not in scope of decision:

For auctions:

- Frequency of auction (assumed monthly)

For continuous trading:

- Business days of trading
- Trading windows per business day (should at least cover all market making windows)
- Market making windows per business day (proposed is a window coinciding with the second MM window in GB)

For products:

- Delivery periods auctioned (not mentioned, presumably up to 12 months ahead), e.g.
 - M+1, M+2,, M+12
 - Q+1, Q+2,, Q+4
- Time of day delivery product offered (baseload, mid merit and peak load products are mentioned), e.g.
 - Baseload
 - Mid merit
 - Mid merit 1
 - Peak load.
- Forward contracting obligations will need to be specified per product type to ensure that obligated volumes are offered on most desired products. On that, product types are left to the market.

It is observed that baseload and peak load are the standard product types traded in European power derivatives futures markets. It is presumed that the product types for forward contracting obligations should be compatible with the products traded in the GB forward market.

- Standard contract size.

In the MMO workout a standard contract size (tick) of 0.1 MW is assumed. This is in line with the tick size practiced in the NZ market and would also be more practical considering MMO volume caps per trading window smaller than 1 MW. Other than compatibility with the forward volume obligation, product size is left to the market.

12 APPENDIX I - MARKET MAKER, INTERNATIONAL EXPERIENCE

12.1 GB MARKET

In 2013 Ofgem initiated their liquidity project. Ofgem was concerned that poor liquidity in the wholesale electricity market was posing a barrier to effective competition. Ofgem intended to intervene in the market to improve liquidity.

During the summer of 2013 Ofgem had consulted the market on policy options for this intervention and in November 2013 they consulted on a draft for a special license condition for the eight largest electricity generating companies in the UK: Centrica, Drax, EDF Energy, E.On, GDF Suez, RWE npower, SSE, and ScottishPower¹¹.

The license modification introduced:

1. rules to improve access to the wholesale market for small market participants by establishing a framework through which small suppliers can seek agreements to trade with obligated generators
2. an obligation to post bids and offers available to the wholesale market to ensure that all market participants have opportunities to trade every day in a range of peak and baseload products along the curve
3. a requirement to submit regular reports to the Authority to facilitate an assessment of the level of liquidity in wholesale electricity markets.

The remainder of this paragraph focuses on part 2. “the introduction of an obligation to post bids and offers available to the wholesale market to ensure that all market participants have opportunities to trade every day in a range of peak and baseload products along the forward curve”.

The decision on the special license conditions was made 23 January 2014 with entry into force from 21 March 2014¹².

Schedule B¹³ of the special license conditions specifies the obligation put on the eight designated licensees as mentioned above. The obligation entails to offer during

12

https://www.ofgem.gov.uk/sites/default/files/docs/2014/01/decision_notice_under_section_11a1a_of_the_electricity_act_1989_0.pdf

specified time windows of each trading day on one of the qualified platforms specified buy and sell volumes for specified products, with specified maximum bid/ask price spread per product.

Trading windows

The quotes must be provided each Business Day during two 1 hour trading windows starting at 10h30 and 15h30 respectively.

Prices and products

The Products that must be quoted during each trading window and the maximum bid/ask price spread allowed are as follows:

	Baseload	Peak
Month+1	0.5%	0.7%
Month+2	0.5%	0.7%
Quarter+1	0.5%	0.7%
Season+1	0.5%	0.7%
Season+2	0.5%	0.7%
Season+3	0.6%	1%
Season+4	0.6%	N/A

Volumes

For each specified product a buy and sell quote must be provided for a volume of 5 MW each and for a volume of 10 MW each.

Where a bid or offer for a product is accepted, a new bid and offer for the product must be posted ultimately within 5 minutes after acceptance of the first bid or offer.

Suspension of obligation

If at any time during a trading window the difference in accepted buy volume and accepted sell volume exceeds 30 MW, the quote obligation ceases for the remainder of that trading window.

If at any time in a trading window, a product has been traded at a price which is more than 1.04 or less than 0.96 times the price at which the product was first so

¹³ See chapter 3 in https://www.ofgem.gov.uk/sites/default/files/docs/2014/03/liquidity_in_the_wholesale_electricity_market_special_condition_aa_of_the_electricity_generation_licence_-_guidance.pdf

traded within that time window, the quote obligation ceases for the remainder of that time window.

All suspended quote obligations resume at the next trading window.

Reported results

Using churn as liquidity indicator, Figure 16 below shows a constant improvement of churn compared to the year before since the introduction of the MMOs on 21 March 2014.

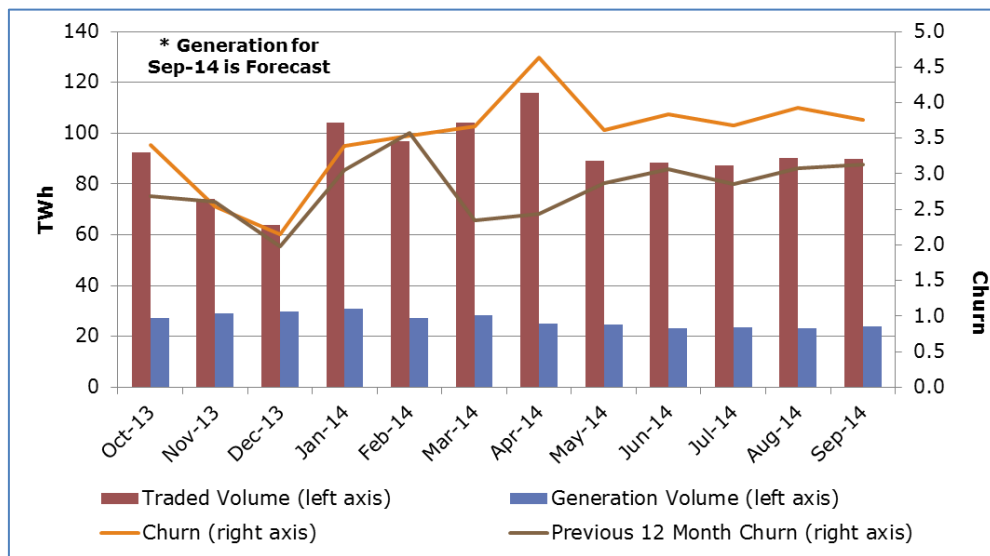


Figure 15: UK electricity wholesale market monthly churn Oct-13 - Sep-14 (Source: Ofgem)

In addition, price spread trend indicates further reduction of price spread since the introduction of MMOs.

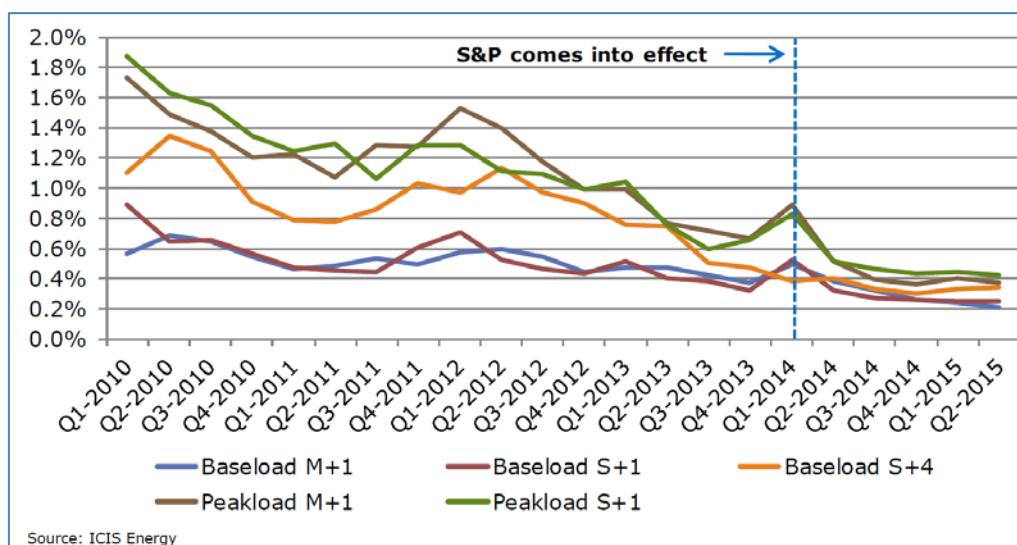


Figure 16: Bid-offer spread trend in UK electricity wholesale markets Q1 2010 - Q3 2014 (source: Ofgem)

Furthermore, Ofgem reports the following results on MMOs:

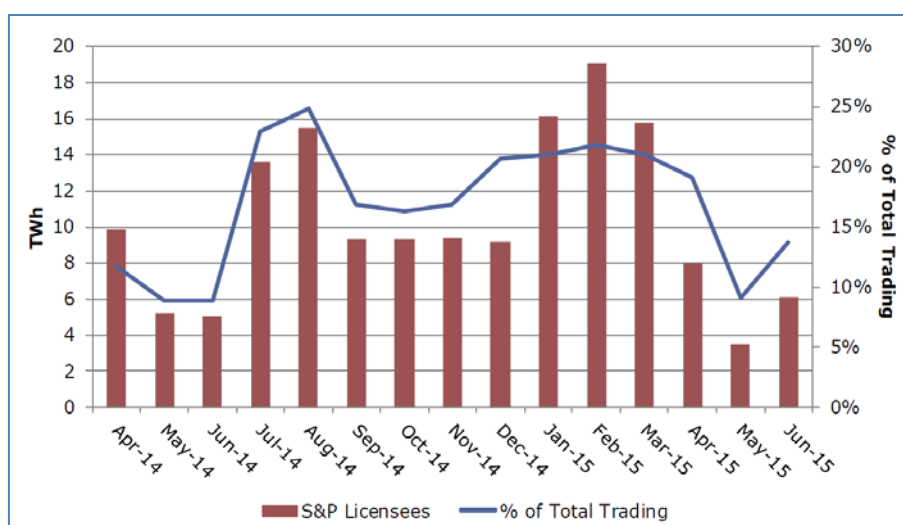


Figure 17: Market making volumes traded in UK electricity wholesale market Apr-14 - Sep -15 (source: Ofgem)

On average, MM trades contributed to around 15% of overall trade. A possible explanation for the declined share of MM volumes traded during Q2 2015 is the overall declination of OTC traded volumes.

12.2 NEW-ZEALAND MARKET

In their May 2015 consultation paper on Market Making arrangements for the New Zealand wholesale electricity market, the New-Zealand Regulatory Authority sought opinions on their intended policy to introduce market maker obligations for baseload futures on ASX, the wholesale market forward trading platform for New-Zealand. The NZ Authority opted to only introduce market maker obligations for baseload options and not for peak futures or quarterly options products.

Current situation

In the ASX NZ market, the four largest generator-retailers (being Contact Energy, Genesis Energy, Mighty River Power, and Meridian Energy) have each separately formed an agreement with ASX to provide market making services. These agreements are formally known as Daily Settlement Liquidity Provider Agreements.

The agreements have been entered into voluntarily. They are annual contracts that the four market makers had each entered into by mid-2010, and have re-signed each year since that time.

With encouragement by the NZ RA the spread was reduced from 10% to 5% in October 2011. In June 2014 market making for monthly baseload futures was

introduced on top of the already existing market making for quarterly baseload futures.

The voluntary market maker agreements imply a firm commitment to market make:

- each business day between 3.30pm and 4.00pm
- for both Otahuhu and Benmore contracts
- in quarterly baseload futures extending out at least three years
- in monthly baseload futures extending out three months
- with a maximum bid-offer spread of 5%
- with minimum volumes of 3 MW on each side (i.e. available to buy and sell) for the quarterly baseload futures, and 2 MW for the monthly baseload futures
- with a requirement that, if a contract trades, a new price is posted within 60 seconds (i.e. the “refresh rate”) – though this only applies for 1 MW per such event per trading day
- with an allowance to pull back from their commitments for short periods if their trading portfolio is under stress

In return for providing market making services, the market makers receive some incentives from ASX. These primarily relate to a rebate of ASX transaction fees for any trading they engage in.

Results

Looking at the trade volumes reported by EMI forward liquidity started to develop shortly after the MM introduction mid 2010, with a growing increase since the introduction of a reduced market maker price spread in October 2011 and an additional liquidity boost since the introduction of monthly market maker products in June 2014.

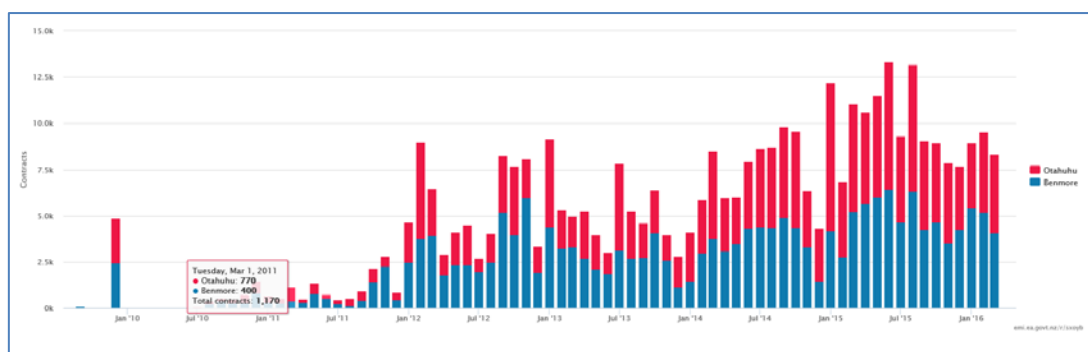


Figure 18: Traded volume of futures in NZ wholesale electricity market (source www.emi.ea.govt.nz)

Moreover, price spreads are on average 80% below the MM price spread limits as the following figure demonstrates:

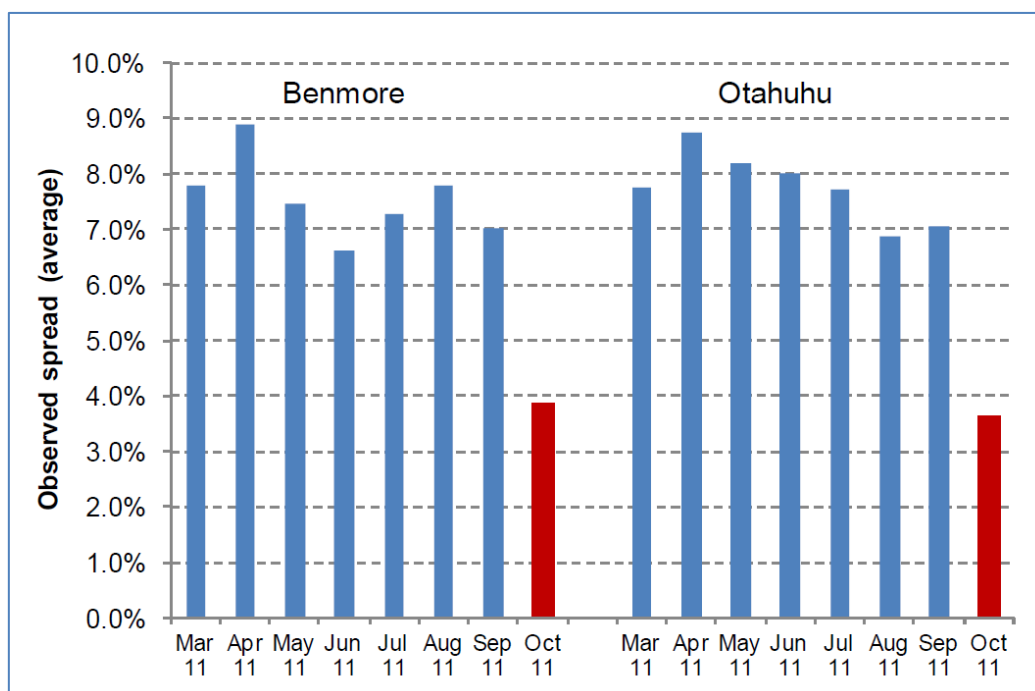


Figure 19: Observed spreads for ASX NZ futures contracts (source: NZ EA)

Average observed price spread under an MMO price spread limit of 10% was below 8% while price spread dropped to below 4% after the introduction of a 5% price spread limit in the MMOs.

Developments

Only 4 out of the 5 biggest players in the New Zealand electricity market agreed to enter into the voluntary arrangements.

One of the concerns of the NZ RA is the free-rider concern of the 4 market makers with respect to the fifth one which claims not to be able to enter into market making because of lack of firm generation in its portfolio. Another concern is that participation from financial institutions in the futures market is limited due to the risk incurred by the uncapped NZ spot market price and therefore NZ RA sought to introduce a new cap future product.

In its consultation paper the NZ RA investigates three policies towards improved market maker arrangements among which the option to implement mandatory arrangements. “The primary obstacle to achieving anything further is that the market participants may not be prepared to voluntarily support price making for new products (e.g. the cap product) or undertake the other desirable improvements to market making identified in this paper. If this issue cannot be overcome, the

Authority is concerned that voluntary arrangements may be insufficient on a long-term basis.”

Although preferring a voluntary approach, the NZ RA expressed limitations in what can be reached with this approach especially with respect to improvements such as the new cap future product they deem necessary.

On 8 December 2015, NZ RA decided to leave the existing voluntary arrangement intact and only pursue on the development of an MMO for a cap product that would attract financial institutions to the forward market. The NZ RA will complete its forward market MMO arrangements in 2016.

12.3 NORDIC ID MARKET

Another example for market maker arrangements stems from the Nordic continuous trade intraday market. Although this is not a forward market, the market making arrangements are also exemplary although applying to a physical product and a different timeframe.

Market maker contracts are entered into by Nordpool Spot with interested market parties on a voluntary basis. Contracted parties receive compensation in the form of a free trading membership and a reduction of trading fees.

The market maker commits to quote on each Trading Day from 30 minutes after start of Trading Hours until end of Trading Hours binding bid prices for buy and sell volumes of Products in contracted market areas with a minimum volume and requirements of spread.

The spread allowed depends on the DAM price of the market as follows:

ELSPOT price [EUR/MWh]	<20	20-40	40-60	60-80	>80
Market Maker Spread		5	10	15	

The volume obligation is not standardized and may vary per party.

Any order quoted by a Market Maker shall be replaced with a new order without unfunded delay after a transaction is carried out.

The market maker has the right to be released from his quoting obligation for an aggregate period of 10 Trading Days per calendar year as well as for an aggregate period of 30 minutes each Trading Day except during the last 15 minutes of the Trading Hours of that Trading Day.

A market maker holding inside information is released from his quoting obligation until such information is made publicly available.