Evaluation of Hedge Market Liquidity

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for

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The views, opinions, analysis and conclusions given in this report are based on independent work undertaken by Energy Link and do not represent the views of the Electricity Authority.

Contents

1 Introduction

The Ministerial review of the performance of the electricity market in 2009 resulted in the Government placing obligations on the major generators concerning hedge market arrangements. All major generators (with over 500 MW of capacity) were requested to put in place by 1 June 2010 an electricity hedge market with the following characteristics:

- standardised, tradable contracts;
- a clearing house to act as a counter-party for all trades;
- low barriers to participation and low transaction costs;
- market-makers to provide liquidity.

The Minister set a deadline of 1 June 2010 for implementation of a satisfactory exchange with the above characteristics, with an assessment to be made for satisfactory market depth at 1 June 2011, with the principal yardstick being 3,000 gigawatt hours (GWh) of 'unmatched open interest.'

Energy Link was engaged in May 2011 to undertake a review, and to prepare a report that evaluates the progress the major generators have made toward achieving the Government's expectations concerning a liquid electricity hedge market, and to recommend actions to address shortcomings identified in the evaluation.

Where shortcomings were identified, we have recommended actions for the Electricity Authority (Authority) that will address them, in keeping with the Government's direction to the Authority in section 42(2) of the Electricity Industry Act 2010 (the Act) to facilitate or provide for an active market for trading financial hedge contracts for electricity by 1 November 2011.

Section 3.1 briefly overviews the history of the hedge market since the spot market was established in 1996. Section 3.2 examines the latest reforms for the hedge market and the obligations placed on the Authority in respect of these reforms. Section 3.3 includes a list of electricity futures markets around the world, as context for the developments in New Zealand. Section 3.4 explains the role of the 'over the counter' OTC market and its relationship to the new futures market, and section 3.5 summarises a review of the literature which is relevant to the assessment of hedge market liquidity and to factors which may assist the development of the futures market.

Section 4.1 assesses the performance of the new futures market in terms of its trading, and section 4.2 in terms of its design. Section 4.3 summarises the views of five stakeholder groups and section 4.4 summarises our overall assessment of progress to date including shortcomings relative to the Government's stated and implied expectations.

Section 5.1 lists options for improving performance and section 5.2 contains our recommendations.

This report also contains a Glossary at section 6, examples in Appendix 1 showing and contrasting how the futures and contract for difference (CFD) contracts discussed in this report actually work, the literature review in Appendix 2, and detailed feedback from stakeholders in Appendix 3.

In formulating our recommendations, our approach was driven primarily by the explicit and implied expectations of the Government in respect of the hedge market reforms, and by recognising that developing a truly liquid hedge market, whether futures or any other type of hedge market, requires a change in the "trading culture" of the major players. We believe that the more this change can occur without direct intervention, the better.

For avoidance of doubt, the scope of the study specifically excluded:

1. consideration of any actions that would require restructuring major generators, for example, the compulsory separation of retail and generation business units; and
2. analysing or commenting on whether the Government's expectations for the development of the hedge market represent the best path that hedge market reforms could have taken.

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2 Executive Summary

The hedge market shrank dramatically in size in 1998/99 when what are now Electricity Lines Businesses (ELBs) sold off their retail customer bases and vertical integration took hold. The hedge market currently trades between 25% and 50% of the total physical market, which is substantial but much lower, for example, than in Australia where the futures market alone traded 252% of the total physical market in 2010.

Vertical integration is a valid structure for managing the risks faced by market participants, but there are complementary roles for the hedge and spot markets. Since 2002 successive Government Policy Statements on Electricity Governance (GPS) have identified development of the hedge market as a priority, and a number of reforms have occurred since, including the establishment of the EnergyHedge market in 2004 and a series of measures recommended by the Hedge Market Development Steering Group in 2006.

Our analysis of the latest set of hedge market reforms lead us to two key assumptions:

- the hedge market reforms should enhance competition in generation and in retail, in particular, with an emphasis on the retail sector; and
- in respect of progress on developing the hedge market, time is of the essence.

A third key driver of our recommendations is recognition that the major generators, in establishing a liquid hedge market, will face a significant change in trading culture. The more that this can take place ahead of intervention or regulation, we believe, the better.

In our view, to demonstrate success in and to achieve the Government's objectives, the futures market must exhibit both efficient pricing and the entry of new players. Efficient pricing of futures means that futures prices should reflect an aggregated view of expected future spot prices, and the 3,000 GWh open interest target plays a key role in creating strong incentives for this to happen. Entry of new players into the new futures market, particularly small retailers and financial intermediaries, would be a sign that there is confidence in the wider New Zealand electricity market (NZEM) and in the futures market.

The latest hedge market reforms lead the five major generators to select ASX electricity futures as the exchange-traded hedge market and four have signed market-making agreements with the ASX. The futures market, by definition, meets the Government's criteria for standardised, tradable contracts, and has a clearing house to act as a counter-party for all trades. In principle, if the futures market is liquid then it also has low barriers to participation and low transaction costs, but at present liquidity is lower than desirable, as evidenced by the large bid-ask spreads which currently average 7% - 8%.

Based on feedback from stakeholders, new players are ready to enter the futures market, but are held back by the wide bid-ask spread, and by concerns that the market lacks the depth to support increased trading, and that futures prices are not yet efficient.

In the five months since the EnergyHedge market was disestablished, significant progress has been made: trading volumes have averaged about 200 GWh per month, and open interest has grown steadily until it now sits at about 600 GWh. However, this is well short of the Government's 3,000 GWh target, and it is clear that this was never going to be achieved through organic growth. Realistically, this would have required the addition of open interest using off-market mechanisms which allow existing large hedge contracts to be converted into futures contracts, or by block trades for large hedging trades.

Open interest is growing, and the bid-ask spread has come down from 10%, so doing nothing and allowing the market to evolve naturally is an option. On balance, however, we believe that this will not occur in a reasonable time, and that changes to the market-making agreements are the best way forward. Specifically, the agreements should specify a maximum spread between bids and offers made in the last 20 minutes of each trading day (the period when market-makers are currently active) of no more than 5%. Bids and offers should also be reloaded with time delays no longer than 60 seconds for the front 4 quarters, extending out to 5 minutes for later quarters.

The 3,000 GWh open interest target remains valid and should be expected to be reached within the next 12 months, assuming that changes to the market-making agreements reduce the bid-ask spread and new players do enter the futures market.

In addition, the Authority should look to amend the Code to allow market-making parameters to be set by the Authority based on prevailing trading conditions.

Other key recommendations are:

1. the Authority should investigate how a net futures position could as of right be taken into account in calculating prudential requirements, and amend Part 14 of the Code accordingly (Clearing and Settlement); and
2. To help ensure efficient pricing in the futures market, the Authority should investigate if and how the following information could be provided to the market:
    a. snow-pack energy storage;
    b. the total contract position (retail load plus hedges) of the market;

c. fuel prices for generation.

3 Hedge Market Reforms

The hedge market was defined by the Electricity Commission in 2006 as “the market for the trading of wholesale electricity derivatives”. Electricity derivatives are commonly referred to just as hedges[1], although there are a number of different forms that hedges can take including CFDs, options, futures and more ‘exotic’ forms. A derivative contract literally derives its value from the price of some underlying asset or commodity, in this case the spot price of electricity. Appendix 1 includes an explanation of the more common forms of hedge contract.

There are a significant number[2] of participants in the wider electricity market who could, if they wished, buy or sell hedges, but instead opt for fixed price variable volume (FPVV) contracts. An FPVV contract represents a simpler approach than hedging for buying or selling electricity as it bundles physical supply and protection from spot price risk into one contract. Under FPVV, the price that is paid for electricity in each contract period is set in advance and is the same for all volume delivered throughout each period[3].

For practical purposes, we often think of the hedge market as including those parties that choose FPVV arrangements but who are large enough to hedge if they wished to.

In a market with a low level of vertical integration between generation and retail, the hedge market would be essential for risk management, as it would provide both retailers and generators with a key mechanism by which they would manage their respective exposure’s to the spot price. In the NZEM, however, the majority of the market is vertically integrated so the four or five major players manage their spot exposure primarily by matching their retail load to their generation. Due to the existence of a significant degree of locational price risk (LPR), the major players have also in the past tended to match retail to generation on a regional basis, i.e. by building or buying retail customer bases near to their respective main centres of generation.

The following tables show the size of the hedge market for the last two years including the EnergyHedge market which ceased trading at the end of November 2010, and the ASX futures market which commenced trading in July 2009. The data excludes the virtual asset swaps (VAS) required of the three state owned enterprises (SOEs) that are major generators pursuant to the latest package of reforms. To put these numbers in context, hedge market trading for the two years ranged between approximately 25% and 50% of the total physical market: these are substantial percentages and demonstrate that there is already a relatively large hedge market whose participants include spot market participants, both large and small, and large consumers (defined as consumer whose average load is approximately 1 MW or greater).

[1] In actual fact, a hedge is anything that offsets a pre-existing risk, so the concept is not just limited to derivatives.
[2] Based on hedge market data from February 2009, the number exceeds 100.
[3] A small number of hybrid FPVV contracts do exist in which the price fixed up to a point, then spot price is paid above this point.

Table 1 - Volume of Trade in the Hedge Market in GWh (excl VAS)

GWh	CFD	EnergyHedge	FPVV	Option	Futures	TOTAL
YE April 2010 (excl. VAS)	10,946	479	3,356	4,899	141	19,822
YE April 2011 (excl. VAS)	4,464	659	3,077	125	1,623	9,948

Table 2 - Relative Volume of Trade in the Hedge Market (excl VAS)

Percentage of Total	CFD	EnergyHedge	FPVV	Option	Futures	TOTAL
YE April 2010 (excl. VAS)	55%	2%	17%	25%	1%	100%
YE April 2011 (excl. VAS)	45%	7%	31%	1%	16%	100%

As a result of vertical and regional integration, however, the hedge market has remained small relative to the total size of the physical market, when compared to other electricity markets where hedge trading is more active (for example, in 2010 the Australian electricity futures traded 252% of the total physical market). Poor liquidity in the hedge market has often been cited as a barrier to the entry of new market participants, particularly new retailers who look to the hedge market as a key part of their risk management strategy, upon which to build a retail presence.

This should not be taken to imply that vertical integration is bad, and the Ministerial review recognised that mandatory separation of retail from generation, as a measure which would dramatically increase the size of the hedge market, "would increase transaction costs and the riskiness and costs of both generation and retailing". Commentators and researchers have also argued that vertical integration provides a "natural and self-sustaining solution to electricity sector problems" (Tussing and Hatcher 1994; Meade and O'Connor 2008). But it must also be recognised that vertical integration is a partial solution and that there are complementary roles for the hedge and spot markets.

3.1 History of the Hedge Market

The hedge market was once significantly larger: when the spot market was established in 1996, the Electricity Corporation of New Zealand (ECNZ) and Contact Energy[4] between them owned over 95% of all generation, but had few retail customers[5]. At that time, Electricity Supply Authorities (ESAs) of the day, most of whom became ELBs after 1998, had retail customer bases in their respective network areas, and most required hedges to a greater or lesser extent to cover the resulting spot exposure. Back then the hedge market may have, at times, exceeded the total physical market.

But in 1998 the Electricity Industry Reform Act (EIRA) became law and required ESAs to choose between their lines and the energy business: most chose lines, resulting in a massive sell-off of retail customers to Contact Energy, to the three new SOEs[6] created by the EIRA on 1 April 1999, and to smaller players remaining in the retail business, including Trustpower. By mid 1999, the level of vertical integration in the NZEM had moved from low to high, and the hedge market shrank accordingly.

The NZEM's first futures contract was established on the New Zealand Futures and Options Exchange (now part of the ASX), and settled on the average spot price at the

[4] Contact was split out of ECNZ in February 1996.
[5] A notable exception was the supply contract between ECNZ and New Zealand Aluminium Smelters.
[6] Genesis Power, Meridian Energy and Mighty River Power.

Haywards node each month for a contract size of 250 MWh (336 kW - 372 kW depending on the length of the month). The contract was established early in the history of the spot market and traded to a reasonable degree until 1998, when vertical integration became prevalent and futures trading dried up, and it was subsequently withdrawn in 2002.

Since 1999 the hedge market has continued to play an important role in the NZEM, despite on-going concerns over liquidity which have prompted a number of attempts to improve its functioning. The hedge market is still viewed as important for two reasons, the first and most obvious being its role in allowing parties to manage risks which are not covered by vertical integration. For example, retailers that do not own generation, or whose retail business significantly exceeds their generation business (net retailers) usually seek cover for their net spot exposure in the hedge market.

The second and less obvious reason is that, given key assumptions (refer to section 3.4), hedge prices reflect expected spot prices. Of course, everyone's view of the future will be different, but the fact that two parties can agree to transact in a hedge implies that their views are close enough. In a fully liquid hedge market, therefore, the price of hedges actually traded is an indication of the market's aggregate view of future spot prices. In this case hedge prices provide a signal to the market which is useful in many contexts including investment in and location of new generation, acquisition of new customers, and decisions that larger consumers make about investment in production.

A "forward curve" is defined as a graph, chart or table showing the prices of the most recently traded forward contracts against the period they relate to. Hedge and futures contracts are both types of forward contracts, so if the hedge market were liquid then its forward curve would provide an indication of expected spot prices, and hedgers would have good information with which to decide whether they would prefer to hedge or be exposed to the spot price. Of course, spot prices fluctuate widely (and wildly at times) depending on many factors, so the actual spot price will almost always turn out to be different to the forward price, and sometimes very different, so the degree of volatility in spot prices is another important factor that is taken into account by hedgers: some may wish to eliminate their exposure to spot prices, others may prefer to accept a degree of exposure.

Given the importance of the hedge market, and the high level of vertical integration in the NZEM, getting greater liquidity in the hedge market is a perennial issue, and the "Government Policy Statement on Electricity Governance has sought the development of a more liquid hedge market for many years" (Minister_of_Energy 2009).

The GPS[7] of December 2000, revised February 2002, required that the industry "ensure that aggregate information on hedge prices is made available, and should take steps to promote the development of trading markets that discover forward prices for electricity", and in April 2002 a hedge index was first published, providing aggregated data on hedge and FPVV prices at Haywards, Benmore and Otahuhu.

In 2003 the GPS noted that "a transparent and liquid hedge market is a critical component of an efficient wholesale market. It enables market participants to manage

[7] Old GPS' are available at http://www.med.govt.nz/templates/ContentTopicSummary____21482.aspx

their risks and facilitates retail competition. By and large the current hedge market does not appear to operate particularly well". The GPS also signaled the Government's intention to empower the Electricity Commission to "establish and promote hedge markets" and included a list of possible interventions including the requirement to make generators participate in a hedge market.

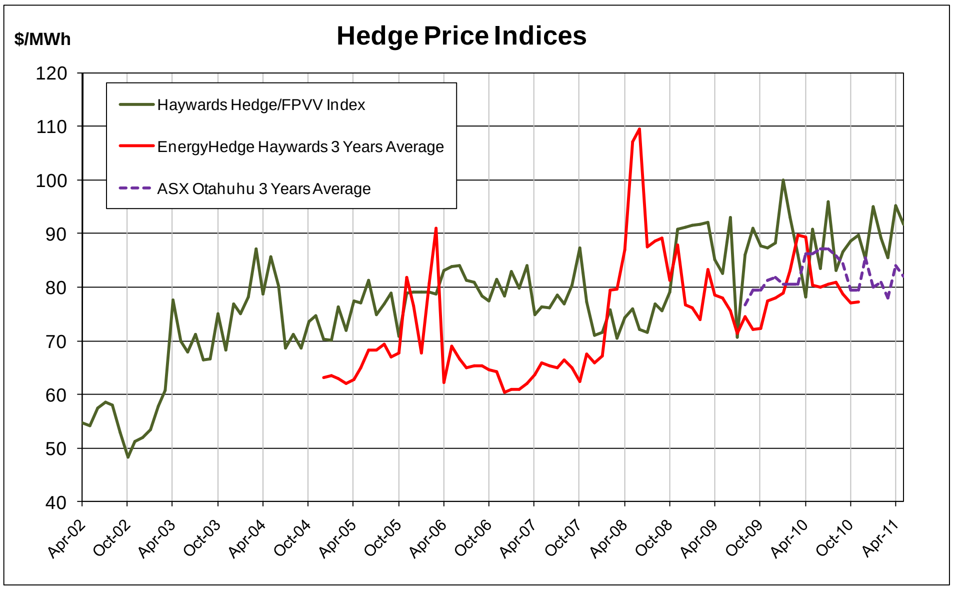
The GPS of 2003 also included a requirement for the EC to oversee development of financial transmission rights (FTRs) for the hedging of LPR.

In December 2004 the EnergyHedge market, set up by the five major generators to facilitate bilateral trading of CFDs referenced to Haywards, commenced trading. Bids, offers and traded prices were available for all to see on the EnergyHedge web site until November 2010 when EnergyHedge was disestablished in favour of futures trading on the ASX.

EnergyHedge had the five largest generators as participants[8] and traded 0.25 MW base-load CFDs referenced to the Haywards node. All participants were market-makers, making bids and offers within 10% of each other[9], and the CFDs were bilaterally traded using a standard hedge contract. The market traded for one hour each business day, with no limits on the number of trades allowed. Volumes were relatively small, for example for the period February to June 2009, 344 trades totaling 913 GWh (2.4% of the physical market) were made on EnergyHedge. Near the end of its life, contracts were also traded for Benmore and Otahuhu.

Figure 1 shows average hedge prices at Haywards for EnergyHedge contracts (averaged over a three year forward period), the price of ASX futures contracts traded at Otahuhu (also averaged over a three year forward period), and an index of all other hedge and large FPVV contracts traded, expressed relative to the Haywards node.

Figure 1 - Hedge Market Indices



8 ANZ bank was also a participant for a while from September 2007.
9 The actual spread between bids and offers reduced over time to about 6% on some contracts.

Late in 2004 the EC formed the Hedge Market Development Steering Group (HMDSG) to "provide advice to the Commission on the development and implementation of a transparent and liquid electricity hedge market" (Electricity_Commission 2006). The HMDSG noted that "concerns have been repeatedly expressed since before the electricity market was started in 1996 over whether the ability to hedge is adequate" and agreed on five key problems related to managing the risk of spot exposure:

- "lack of robust information about forward prices, fuel levels, planned plant outages, and so on, available to parties involved, or potentially involved, in price risk management;
- lack of confidence in the competitiveness of the market for term contracts;
- lack of a suitable instrument to manage locational-based or transmission price risks;
- high participation and transactions costs;
- the general lack of understanding in the electricity market place of the advantages, techniques, and uses of price risk management."

As a result of the work undertaken by the HMDSG:

- the Electricity Commission implemented a web site[10] through which hedge contract data is disclosed;
- the EnergyHedge web site was enhanced by the addition of several new contracts;
- work on LPR and FTRs was accelerated, eventually leading to a proposal in 2010 for inter-island FTRs;
- a standard Schedule was developed for the standard ISDA hedge agreement;
- outage information was improved on the POCP web site[11]; and
- an annual survey of hedge market participants was initiated.

3.2 The Latest Reforms

The hedge market reforms of 2009/10 are the latest in a long list of reforms going back to 2002, driven by on-going concerns that the hedge market is not serving the best interests of the NZEM.

In March 2009 Cabinet agreed terms of reference for a Ministerial Review of electricity market performance to be undertaken by MED and an Electricity Technical Advisory Group (ETAG). MED and the ETAG produced a discussion document in August 2009 and, in part, concluded that the "rate at which retail prices have risen, especially for residential consumers, appears excessive when compared to the increase in the cost of new supply" and that one of the three underlying causes of this is "insufficient competition in the retail market, especially outside the main centres, combined with scope on occasion for the exercise of market power in the wholesale market." The report noted that "the hedge contract market is also less transparent and liquid than desirable" and considered, but rejected, the option of mandatory hedging.

After a period during which submissions were received and reviewed[12], the full list of market reforms agreed to by Cabinet included the introduction of a more liquid hedge

[10] Refer to http://www.electricitycontract.co.nz/
[11] Refer to http://pocp.redspider.co.nz/
[12] The submission from Meridian Energy proposed that generators be obliged "to place a certain proportion of their generation through an approved electricity futures trading exchange, ensuring

market (Minister_of_Energy 2009). The cabinet paper noted that "the absence of a liquid energy hedge market, combined with vertical integration of generator-retailers (and the absence of transmission hedges), makes it difficult for new retailers and generators to enter the market, and reduces hedging options for major electricity users."

The paper stated that the hedge market proposal "offers considerable potential to encourage new retail competition and independent generation investment as well as better risk management generally".

All major generators (with over 500 MW of capacity) were requested to put in place by 1 June 2010 an electricity hedge market with the following characteristics:

- standardised, tradable contracts;
- a clearing house to act as a counter-party for all trades (which makes trades anonymous);
- low barriers to participation and low transaction costs;
- market-makers (offering buy and sell prices with a maximum spread) to provide liquidity.

The Minister set a deadline of 1 June 2010 for implementation of a satisfactory exchange with the above characteristics, with an assessment made for satisfactory market depth at 1 June 2011, with the principal yardstick being 3,000 GWh of 'unmatched[13] open interest'.

Section 42 of the Act requires the Authority to have amended the Code so that it facilitates, or provides for, an active market for trading financial hedge contracts for electricity by 1 November 2011. To the extent that the Code is not amended to do this, the Authority must report back to the Minister and:

1. identify which parts of the new active hedge market are not included in the Code;
2. explain why the Authority has not included these parts;
3. suggest alternative methods by which the new active hedge market could either have been or could be facilitated or provided for;
4. set out if, when, and how the Authority proposes to facilitate or provide for a new active hedge market.

The Act also gives the Minister power, which must be exercised between 1 November 2011 and 31 October 2013, to amend the Code if the Minister considers that this is necessary to achieve the objective of creating a new active hedge market: the onus is on the Authority to demonstrate substantial progress by November 2011.

The objective of the hedge market reform is to "provide liquidity and open access for new entrant generators and retailers and consumers". Hedge market reform comes under the heading of measures to improve retail competition (Minister_of_Energy 2009), so in policy terms, enhancing and increasing retail competition is the key driver of the reforms listed above.

liquidity". The submission from Mighty River Power proposed that the EnergyHedge platform could support "some form of mandatory hedging".

[13] Or simply 'open interest'.

Our analysis of the latest reforms leads us to two key assumptions which ultimately drive our recommendations. The latest hedge market reforms are motivated primarily by concerns over the lack of retail competition, and unlike earlier reforms, include explicit targets for the time in which the market is to evolve to a specified state. Our two key assumptions are that:

1. the hedge market reforms should enhance competition, in particular, in the retail sector; and
2. in respect of progress on developing the hedge market, time is of the essence.

Assuming that the reforms achieve their objective, then the requirement on the major generators to be market-makers will increase the importance of the hedge market in managing their spot exposure. In the short to medium term this will be achieved by compelling the major generators to provide liquidity in the hedge market to the extent that encourages new entry, and introduces additional competitive pressure and potential threats to the major generators. But over time, we assume that the major generators will adapt their respective trading cultures to the new trading arrangements and may even come to see opportunities in and around the hedge market.

Given that the hedge market must exist alongside, and complement vertical integration, as a strategy for electricity risk management, this raises the question: how large should the hedge market be to achieve an optimum outcome in the longer term? In principle, the optimum is reached when the marginal benefits arising from an improved hedge market equal the marginal costs of creating and sustaining it (in present value terms). The benefits of an improved hedge market are likely to arise through more efficient retail pricing in regions where currently prices appear to be high through a lack of competition, and through dynamic efficiency gains associated with innovation that is driven by greater competition and the entry of new players. The costs of improving the hedge market include the direct costs for major generators in their market-making roles plus any loss of efficiency associated with an overall reduction in the level of vertical integration.

The ideal size of the new hedge market is not easy to estimate in a quantitative sense, but the Minister has provided us with a figure of 3,000 GWh open interest as a starting point. This figure is, in our opinion, large enough to create strong incentives for the market-makers to price their bids and offers efficiently, but not so large as to be unattainable in the medium term. A smaller figure may suffice, but without knowing the details of each market-maker's total contract position, it is difficult to make any sensible estimate. Overall, we are content to retain the 3,000 GWh open interest as a key indicator of progress in hedge market reform.

Finally, in our view, in order to demonstrate success and to achieve the Government's objectives, the futures market exhibit both efficient pricing and the entry of new players, specifically:

1. **Efficient Pricing**
   Futures prices should reflect an aggregated view of expected future spot prices: the 3,000 GWh target plays a key role in creating strong incentives for this to happen;

2. **Entry of New Players**
   The new futures market should be attractive to new players, be they existing smaller market participants or new entrants.

3.3 Other Electricity Futures Markets

In this section we briefly review other electricity futures and forwards markets, with the aim of putting our new futures market into a global context. Electricity derivatives are traded on a handful of exchanges and most trading volume is concentrated in electricity futures contracts (Wilkens and Wimschulte 2007).

- **ASX Australian Electricity Futures**
  Trading of 1 MW electricity futures and options commenced for the Australian market (East Coast market) in 2002. All contracts are 1 MW for one quarter for between 13 and 17 quarters ahead.

  Total trade in futures and options for Australian electricity in 2010 increased 53% over calendar 2009. Traded volume equated to 490,000 GWh or the equivalent of 252% of the underlying East Coast system demand[14], and open interest grew to 70% of annual underlying demand. Both electricity market participants and financial trading entities were heavy users of the futures market.

- **CME Group, USA**
  A large range of futures contracts and options on futures at nodes in the US and Canada, with most settling against the spot price but some settling against the day-ahead price in the PJM[15]. Contract sizes range from 5 MW to 50 MW for a variety of terms primarily monthly but some out to 6 years.

- **European Energy Exchange (EEX)**
  German and French electricity futures with either physical[16] or financial settlement, with week, month, quarter and year terms. OTC contracts can also be registered with the exchange and settled via the EEX clearing house. Contract size 1 MW.

  In 2010 157 participants were licensed to trade and the exchange traded 1,208,000 GWh of which 712,000 GWh was cleared OTC and the balance of 496,000 GWh was futures. On 31 December 2010 total open interest was 568,900 GWh.

- **Intercontinental Exchange (NYSE: ICE)**
  Peak and base-load daily and monthly UK electricity futures. Contract size 1 MW with a minimum of 5 contracts per trade (i.e. 5 MW).

- **Eurex**
  Futures and options on German electricity, contract size in 1 MW, week, month, quarter and year terms with a mix of base-load, peak and off-peak.

[14] Source - d-Cypha Trade http://d-cyphatrade.com.au/newsroom/energy_focus/calendar-2010-review
[15] 'Pennsylvania New Jersey Maryland' electricity market covering the eastern interconnection in the US.
[16] With physical settlement, if the futures contract is held to its settlement date, then physical supply of electricity is required.

- **APX-Endex**
  Electricity futures contracts for the Netherlands, Belgium and UK markets[17], settled by physical delivery. Contracts are a mix of base-load and peak with terms from 3 months to 5 years. Contract size is 1 MW in all three country markets.

  APX-Endex advertises market-making on all futures contracts: "The exchange is supported by liquidity providers, who guarantee a constant supply of bid and ask prices within certain spread limits".

- **NASDAQ OMX**
  This exchange trades Nord Pool contracts (and also German and Dutch power) and includes futures, forwards, options and contracts which are analogous to FTRs. Futures are traded short term out to 6 weeks, then forwards can be traded out to 5 years. Minimum contract size in all cases is 1 MW. In 2009 Nord Pool traded 1,220 TWh compared to (Gjolberg and Brattested 2011) roughly 400 TWh of generation in the Nord Pool area.

All of the exchanges trade futures and most trade options, some clear OTC contracts, but only the NASDAQ OMX exchange trades forward contracts. These are settled somewhat differently to futures contracts: although daily settlement is calculated in the same way as for futures, and the value accumulated, no margin payments are possible until the start of the period the contract relates to, e.g. a quarter. During the contract period daily settlement works in the same way as it does for futures, with the possibility of margin calls, and must be supported by either cash or by bank guarantee. We are not aware if this exchange was considered by the major generators prior to selecting the ASX, but these contracts might (or might not) appeal to a wider range of large consumers due to the lesser burden of daily settlement, and might be worth further consideration.

Also of note is that at least two of the exchanges above, APX-Endex and NASDAQ OMX, use market-makers to guarantee that bids and offers for futures contracts will be available with prices within a maximum spread between bids and offers.

3.4 The OTC Market

The emphasis placed by the latest reforms on the development of an exchange-traded hedge market, inevitably raises questions: what is the role of the OTC market going forward? How will the OTC and futures market interact? Will the OTC market benefit from the development of a futures market?

In simple terms, the OTC and futures markets serve the same ultimate purpose, which is to provide participants in the NZEM with an effective means by which underlying spot exposures can be hedged, and electricity can be priced. However, the fact that the two markets possess different attributes means that each fulfills a different role within the wider NZEM, as shown in the following table.

[17] Electricity consumption in 2010 was 124,000 GWh, 85,000 GWh, 346,000 GWh, respectively.

Table 3 - OTC and Futures Markets

OTC Market	Futures Market
• Complete flexibility over terms and conditions of hedge contracts • Significant search and transaction costs • Poor liquidity • Lack of transparency in prices[18] • Possibility of substantial credit risk • Spot and hedge cash flows usually occur during the same month (no daily settlement)	• Highly standardised contracts (which may concentrate trading to promote liquidity and lower transaction costs) • Virtually no credit risk • Transparent forward curves • Efficient pricing (assuming that demand from hedge buyers approximately equals demand from hedge sellers) • Daily settlement and margining which means that spot market and futures cash flows do not always offset each other in the same month

The OTC market is substantial in size (refer Table 1) but the hedge sellers are dominated by the major generators, whereas there are at least 100 hedge buyers (including those buying large FPVV contracts). The Haywards hedge/FPVV index shown in Figure 1 can be examined in more detail using the detailed hedge data disclosed since February 2009, and this reveals a high degree of volatility month-to-month (individual contracts can move the index significantly) and a wide spread in contract prices (as much as 30% in any given month): these are both indicative of a poor liquidity.

However, we expect the OTC market to remain important to the NZEM, in particular for those hedgers who do not wish to trade futures: these are likely to be larger consumers, and some of the smallest retailers and generators, or any hedger who requires customised hedge structure, terms or conditions, which are not available in the futures market.

Ideally, however, financial intermediaries will enter the futures and OTC markets, just as they have done in Australia[19], for example, to enhance liquidity in the futures market, but also to act as a bridge between the OTC and futures markets: once the futures market has sufficient liquidity, intermediaries can offer hedge contracts (typically CFDs) to hedgers in the OTC market. Intermediaries are not natural hedgers as they do not have an underlying spot exposure to offset by trading in the OTC market, they in fact create an exposure by doing so. However, they can then offset this risk by trading in the futures market, profiting by doing so.

As an example, consider an intermediary who sells a 1 MW CFD to a large consumer in the OTC market, and suppose this contract is at the Otahuhu node for the December 2013 quarter (Oct - Dec 2013) and its strike price is $82/MWh. If, at the time, the Otahuhu futures contract for the same quarter is trading at $80/MWh and the intermediary buys a futures contract at Otahuhu for that period, then the total cash payout to the intermediary over the life of both contracts (assuming they retain their futures position to expiry of the contract, ignoring the futures initial margin and noting that the quarter is 2,208 hours long) is given by:

[18] Although contract details are disclosed on www.electricitycontract.co.nz there is always residual uncertainty about how each contract is priced in relation to its term structure and detailed terms and conditions.
[19] Anecdotal evidence suggests that half of all trading in electricity futures may be by financial entities.

$$Payout = 2{,}208 \times (\$82 - S_{OTA}) - 2{,}208 \times (\$80 - S_{OTA}) = 2{,}208 \times \$2 = \$4{,}416$$

In other words, the intermediary locks in a profit of $2/MWh on the two trades, to a total of $4,416. A similar argument applies to an intermediary selling a hedge to a small generator in the OTC market, except in that case the intermediary would buy a CFD from the generator and sell a corresponding futures contract.

Why would the large consumer buy from an intermediary rather than from a generator or retailer (as they do now)? The intermediary may be able to offer a better price than a generator or retailer is willing to, there may be other terms and conditions in the hedge contract that are attractive to the large consumer, there may be an existing business relationship with the intermediary, or the large consumer may simply choose not to deal with a generator or retailer.

This example reinforces a key point: if it is to benefit the wider hedge market, the futures market must be sufficiently liquid and efficiently priced to ensure that intermediaries and others can access competitively priced futures contracts when they need them. The corollary of this is that entry into futures by intermediaries is a sign that the futures market is working.

3.5 Literature Review

A literature review was undertaken to determine what guidance is available on how liquidity and pricing efficiency can be enhanced in electricity futures markets, on the role of market-making, and on what factors might determine the success or failure of electricity futures contracts. The review is attached as Appendix 2 and the following summarises our findings.

Taken overall, the body of literature directly relevant to this study is quite small, and inconclusive, apart from indicating what we already know from experience in the NZEM: that establishing successful futures markets for electricity comes with significant challenges.

The new futures market for the NZEM currently meets some of the conditions which, according to the literature, might be expected to contribute to its success, but there are significant gaps. For example, the spot market is highly volatile and large, turning over between $1.8 and $6.5 billion per annum since January 2005, both factors which could contribute to its success.

But two factors could reduce the chances of success: the futures contracts only provide a 100% accurate hedge cover at Otahuhu and Benmore, leaving hedgers with spot exposure at other nodes with potentially significant residual LPR to manage by other means. The spot market also has a relatively high degree of market concentration and a high level of vertical integration, leading to a small number of hedge sellers with no natural incentive to develop futures.

The literature refers to the futures bid-ask spread as the ‘cost of liquidity’ which is effectively the premium paid in return for the ability to trade readily.

Other things being equal, we can expect the bid-ask spread to reduce as volume increases, but other factors may have a substantial impact on the spread, e.g. the volatility of futures prices.

Along with other microstructure factors, it is important to get the contract size and length right to maximise liquidity by attracting smaller players, but there is no guidance in the literature on how the ideal size might be determined.

There is always likely to be competition between the futures and OTC markets. Clearly, the OTC market has dominated until now, and would continue to do so if it were not for the Government's expectation that this will change. Because of this natural tension, however, there is no guarantee that the futures market will succeed.

In theory, futures prices should reflect expected spot prices (or at least an aggregated view of expected spot prices) but whether this relationship will hold or not could depend on a number of factors including the balance between the supply of and demand for futures contracts.

4 Hedge Market Performance

In this section we review the progress that the five major generators have made in meeting the Government's requirements.

A significant amount of progress has indeed been made since the major generators committed to the ASX electricity futures market as the new hedge trading platform, and futures trading took off in earnest in Aug-10. Although the 3,000 GWh open interest target has not been met, open interest has grown steadily and continues to do so. We understand that four market-making agreements are in place with the ASX, and that additional resource has been applied by the major generators to ramp up their participation in the futures market.

Progress is reviewed under two headings: trading performance to date, and market design. We also sought the views of various stakeholders and these are summarised in section 4.3 and given in more detail in Appendix 3.

4.1 Trading Performance

Figure 2 and Figure 3 show total open interest and trading volume, respectively, since the ASX first established New Zealand electricity futures in July 2009[20]. Open interest currently sits at approximately 600 GWh and traded volumes have averaged about 200 GWh per month since September 2010.

The total volume traded since September represents about 6% of the total physical market on an annualised basis. By way of comparison, the Australian electricity futures market was established in the third quarter of 2002 and took about a year to reach a point where open interest across all contracts was 8% of the total physical market, which would be roughly the percentage represented by 3,000 GWh in the NZEM. Open interest then leveled off for over a year after reaching 10% of the physical market, before moving upward again from mid 2005. The low level of vertical integration in Australia at the time was a key factor which assisted the development of liquidity.

[20] The drop in open interest early in April is due to Q1 contracts being settled.

By contrast, it has been less than five months since trading ceased on EnergyHedge (and presumably diverted this trading to the ASX), in which time open interest has reached 1.5% relative to total demand. While this may not be up to the Australian standard, given the high level of vertical integration in the NZEM we regard this progress as substantial and encouraging.

Figure 2 - Open Interest by Day

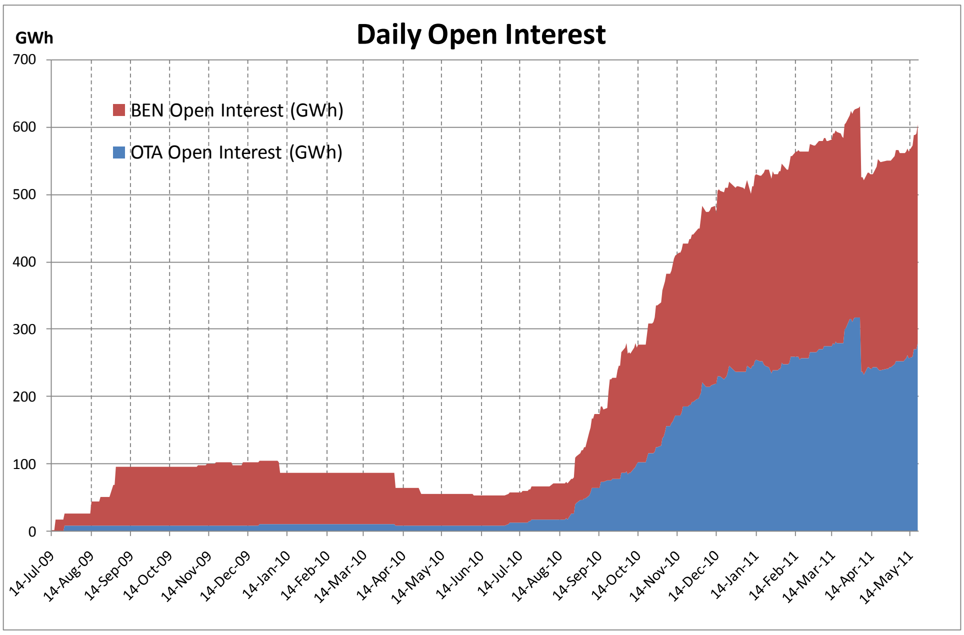
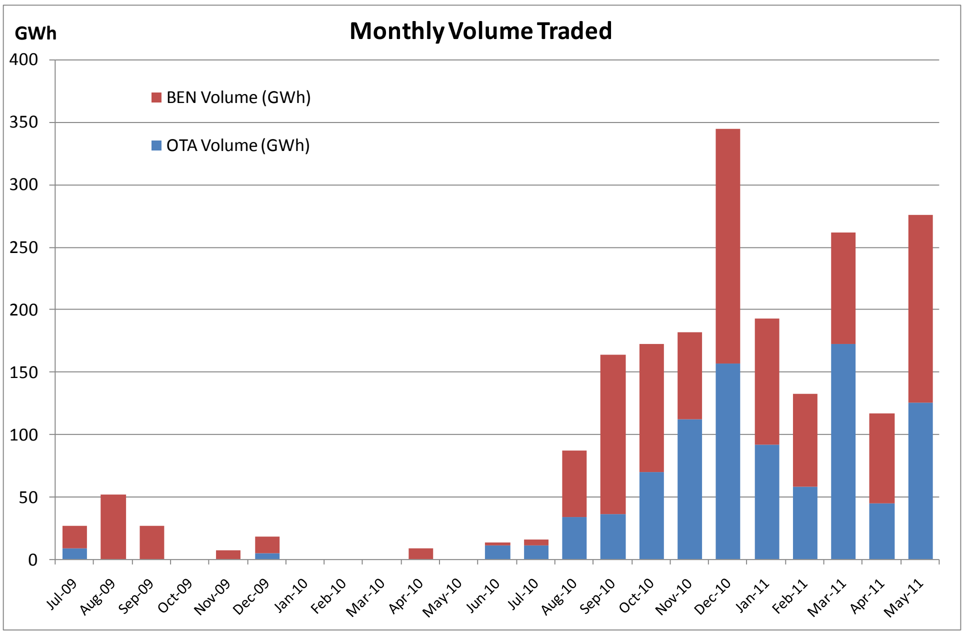


Figure 3 - Futures Market Monthly Trading Volumes



4.1.1 The 3,000 GWh Target

Open interest grew at the rate of 110 GWh per month from August 2010 until December 2010 but then the rate of growth halved: either way the target of 3,000 GWh open interest was never going to be reached through organic growth by June 2011. In all probability, the only way the target could have been achieved would have been to convert existing hedge contracts into futures contracts by a process known as Exchange for Physicals (EFPs) or by making large 'block trades' between major generators in lieu of using OTC hedges. We consider that converting large hedges to futures using EFP or block trades is an entirely valid means by which open interest could be increased to meet the open interest target.

4.1.2 Barriers to Participation

The analysis of barriers to participation in this section is predicated on the assumption that a futures market was the best choice of market, and in the context of trading performance to date. Whether or not futures were the best choice is discussed in section 4.2.1.

Based on our discussions with stakeholders, we are confident that only the major generators are trading in futures at this point. Others are ready to trade but have not yet done so, including intermediaries and smaller retailers. The main reason given for not trading is lack of liquidity: the bid-ask spread is too wide at 7% - 8%, and there are concerns that there is not yet the depth that will allow new entrants to procure the number of contracts they need, or to close out a futures position if and when required. Intermediaries and retailers are concerned that the wide spread would see them buying or selling futures at prices that could easily be undercut by major generators.

Smaller retailers, in particular, are also concerned that the futures prices should be efficient in the sense of being reflective of expectations of future spot prices, otherwise there is a risk that they could be hedging at prices which would reduce their expected margins on sales relative to competitors.

A second potential barrier to participation is the high value of the initial margins, currently ranging from $5,700 up to $46,300, which is high relative to the equivalent Australian electricity futures (AUD $3,100 - $12,200) and most (but not all) initial margins on other electricity futures exchanges. Our discussions with stakeholders indicate that they are not currently seen as a barrier to those who are currently interested in trading. Nevertheless, these are still substantial sums, set relative to worst-case scenarios for changes in futures prices from day-today. They are expected to fall significantly (down to between a few and several thousand dollars) as liquidity develops and also as certainty is obtained around pricing during events such as 26 March 2011 when provisional spot prices hit $20,000/MWh in the upper North Island. Events such as 26 March create uncertainty over future price levels which can translate into sudden changes in futures price, or into lower volumes of trade.

4.1.3 Market-making

The NASDAQ OMX exchange (see section 3.3) describes a market-maker as an exchange "member who commits to continuously quote buy and sell prices on the exchange. The exchange requires that the market maker quotes a maximum spread between buy and sell prices, [and] that minimum volumes are quoted". The market-making parameters are adjusted based on volatility and price levels.

We understand that four market-making agreements are in place and that market-making must take place in the last 20 minutes of trading each day. This has indeed produced results, with bids and offers in every contract through to December 2014, and growth in both trading volumes and open interest.

The bid-ask spread currently averages 7% - 8% and has sat as high as 10%, so we infer from this that there is a requirement of the order of 10% on the maximum difference between market-makers' bids and offers.

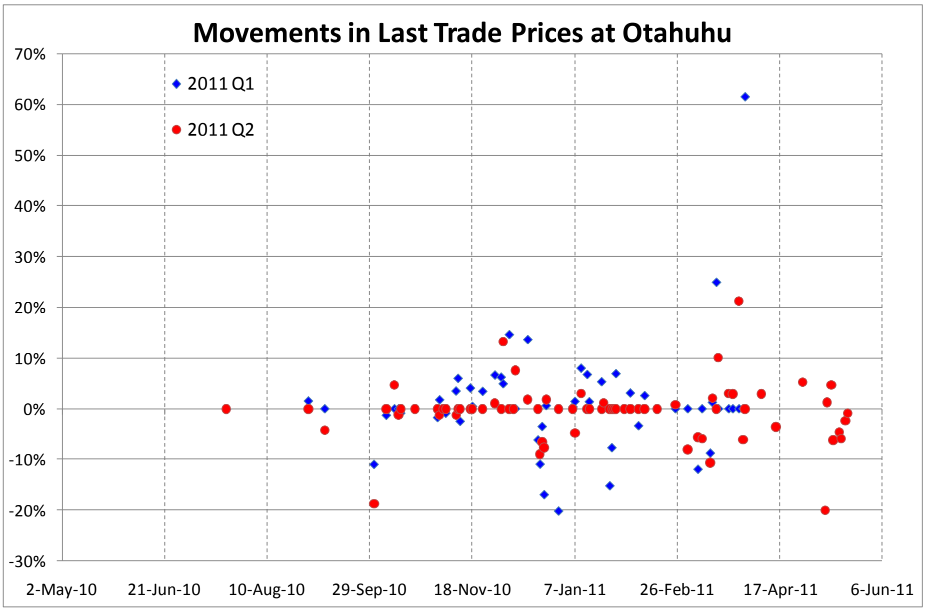
Our assessment of liquidity is based on work sponsored by the Bank of International Settlements, as described in Appendix 2, and covers tightness, depth and resiliency. The tightness of the market is defined by the bid-ask spread which currently averages 7% - 8% across all contracts, although the September 2011 quarter contract at Benmore was recently observed with a spread under 2%. As a comparison, bid-ask spreads on equivalent Australian electricity futures currently range from 0.7% to 3%. Foreign exchange markets are amongst the most liquid in the world and can have spreads of much less than 1%. On the other hand, municipal bond markets in the US are widely regarded as illiquid and can have spreads of several percent. An analysis we undertook in June 2009 showed that on the 'All Securities' list on the main board of the NZX for which there was both a buy and sell quotation (including infrequently traded securities), the average bid-ask spread was 1.33%.

Another way of looking at the optimum bid-ask spread is to ask what spread would provide confidence to new players in the futures market that prices are competitive? Based on our experience assisting various entities buy or sell hedges, we know that the strike price is a key determinant in hedging decisions, and that price differences of the order of \$2/MWh to \$3/MWh can make the difference, i.e. 2% to 3%.

We conclude, therefore, that the market-making agreements in themselves have failed to produce bid-ask spread that are consistent with a liquid futures market. As a result, the futures market has failed to attract the entry of new players, a conclusion supported by our discussions with stakeholders.

Assessing depth and resilience is problematic given the wide bid-ask spread and limitations of the data at our disposal, but anecdotal evidence suggests that the number of contracts on offer has risen from two to five in some quarters. Nevertheless, changes in futures price of 20% or more from day to day are not uncommon, as shown in Figure 4, which suggests that the market is neither deep nor resilient.

Figure 4 - Otahuhu Daily Futures Price Movements



In summary, while a number of market-making agreements are in place, the wide bid-ask spread is a sure sign that liquidity is inadequate, in which case either the market needs more time to allow trading volumes to increase and the bid-ask spread to come down, ideally to 3% or less, or other measures need to be put in place to promote liquidity.

4.2 Market Design

4.2.1 Standardised, Tradable Contracts and Clearing House

By definition, futures contracts are standardised, tradable contracts which are traded on an organised exchange with a clearing system (clearing house plus clearing participants) that guarantees performance of the contracts. The choice of the ASX futures platform has therefore achieved these two requirements.

4.2.2 Barriers to Participation and Transaction Costs

But was a futures market the best choice? The majority of exchange-traded electricity contracts around the world are futures contracts, but there is at least one example of exchange-traded forward contracts.

The Nord Pool, which trades on the NASDQA OMX exchange, features futures contract out to about six weeks, with longer terms offered only in exchange-traded forward contracts (i.e. CFDs) - refer section 3.5 for more details. The advantage offered by these contracts is that the margining process only commences from the first day of the period that the contract covers. For example, if a contract is purchased today for Q4 2013, then daily settlement would accumulate, but without margin calls, through to October 2013, whereas with a futures contract margin calls could be made tomorrow. Daily settlement and margining would still continue for the three months forming the contract period, and cash deposits or bank guarantees would be required to support daily settlement, so these contracts may or may not appeal to parties who would otherwise not choose to trade in futures.

Exchange-traded forward contracts may be worth investigating with the ASX in future if it can be shown that they would have an advantage over futures contracts for periods further into the future, but overall we consider the choice of a futures market to be the obvious one, especially given the relatively short time available to put a market in place and to create liquidity.

Transaction Fees

Transaction fees include ASX exchange fees of $25 per side ($25 for the contract bought and $25 for the contract sold), which is a tiny percentage of the face value[21] of the contracts being traded. In addition, trades made through a broker attract brokerage of varying amounts, but overall the direct transaction fees are low.

Contract Size

Choosing contract size is a trade-off between transaction costs and attracting the widest range of market participants. While electricity futures around the world are generally 1 MW or larger, the NZEM is a smaller market than most, so there may be a valid argument for reducing the contract size below 1 MW, allowing smaller players to participate, and possibly also to facilitate the development of liquidity[22].

A smaller contract would also lower initial margins, helping smaller players enter the market to trade small volumes.

However, while exchange fees may scale down with contract size if the contracts were made smaller, transaction costs also include the time and effort required to fill a trading order. For example, a 5 MW order can be filled with five 1 MW trades but would require twenty 0.25 MW trades. Currently market-making is concentrated in the last 20 minutes of trading, so going significantly smaller than 1 MW would introduce practical difficulties in respect of filling larger orders, such as the need to extend the market-making period to allow larger trades to be made, or the possibility of larger movements in price while filling orders (due simply to the passage of time).

If a new hedge market could be designed from scratch, then there would be an argument for considering a contract size as low as 0.25 MW, but given that we now have 1 MW, three factors suggest that contract size should not be changed in the short to medium term:

1. ASX advises there are practical difficulties in changing the contract size, including substantial delays in gaining approvals and support, the need to split existing contracts, and also system limitations (decimals are not catered for which would require, for example, 250 kW contract size with the corresponding introduction of $/kWh as the pricing unit);
2. financial intermediaries do not want it lower than 1 MW due to the costs of processing orders and the difficulty of filling orders in the relatively short market-making period at the end of each trading day;

[21] The face value of a hedge is equal to the hedge price in $/MWh multiplied by the quantity in MWh.

[22] It is also important to ensure that futures contract size and FTR contract size are multiples of each other to ensure that FTRs and futures contract can be perfectly matched in an overall hedging strategy Energy_Link (2010). Application of FTRs to Hedging Strategy, Part 1: Summary Report. Dunedin, Electricity Commision.

3. those smaller players who would be interested in trading futures in the short term, have indicated they can live with 1 MW: above all they want to see liquidity before they trade, and are concerned that re-litigating contract design could further delay moves to develop liquidity.

In our view, the ideal contract size is somewhere between 0.25 MW and 1 MW. In the longer term, the contract size should be reviewed as the market develops. But in the short to medium term, the feedback from stakeholders strongly suggests that priority should be given to developing liquidity with the 1 MW contracts currently available.

Contract Duration

Feedback from smaller retailers, in particular, indicates that monthly contracts would be useful when matching hedges to retail load profiles, as these can vary significantly from one month to the next. Introducing more contracts has the potential to reduce liquidity, but monthly contracts are sufficiently attractive that they should be discussed further with the ASX and with hedgers.

Daily Settlement

OTC hedges settle in the same month as underlying spot transactions are settled, and many larger consumers, in particular, are content with this system as it reduces the need for daily market operations. While this is a barrier to futures participation for consumers, if they can easily gain access to OTC hedges priced close to futures then they will receive most of the benefits of an enhanced hedge market without having to be set up for futures trading. In Australia, for example, we understand that only a handful of industrials participate directly in the futures market, but they gain the benefits of liquidity in the futures market via intermediaries or physical market participants who sell OTC product at prices close to futures prices[23].

In any case, daily settlement is a mechanism which helps to minimise credit risk in futures exchanges. Any exchange-traded electricity contract will have mechanisms which minimise credit risk, so moving to an exchange-traded forward, for example, might simply swap one barrier for another. So taken overall, although daily settlement might on the face of it appear to be a barrier to entry, the Government requirement for exchange-traded contracts means that it is here to stay in some form or other.

Daily Market Operations

Large physical market participants (generators and retailers) have resources devoted to continuous market operations, but large consumers typically do not. Consequently, the majority of larger consumers are not set up to monitor their futures position on a daily basis, to manage margin calls, or to look for opportunities to optimise their overall energy strategy through active futures trading. As a consequence, they prefer OTC hedges that are settled monthly at the same time as their spot purchases. Based on experience in Australia and feedback from stakeholders, we expect only a small number of larger consumers to trade futures (three or four perhaps), but otherwise the operational and management requirements of futures trading will remain a barrier to most.

[23] The margin can be as small as a few cents per MWh on large trades, although we doubt they will be this low in New Zealand, where we consider margins of $1 - $3/MWh more likely in the longer term.

Credit risk

The ASX clearing house and clearing participants guarantee performance of all futures contracts, so credit risk is effectively nil and is therefore not a barrier to participation.

4.3 Feedback from Stakeholders

As part of the study, a number of stakeholders were contacted and asked for their views on progress in meeting the Government's requirements, whether they would consider trading in futures, and what factors, if any, are currently preventing them from doing so.

We interviewed five small net or pure retailers, five small net or pure generators, six large consumers and five financial entities. Appendix 3 contains details of the feedback from these four groups and from major generators.

In summary, the key points to be taken from stakeholder feedback are:

- small retailers are keen to see liquidity develop (bid-ask spread reduce), and for futures prices to be efficient, so that they can be confident to include futures in their hedging strategies;
- small generators are the group least likely to make use of futures in the short to medium term;
- a handful of large consumers may trade futures, but most prefer to use OTC hedges or FPVV contracts;
- one or two financial entities are prepared to act as intermediaries but are waiting to see the bid-ask spread reduce and for depth to ensure they can trade in adequate volume;
- major generators generally support the development of the futures market and applied additional resource to futures trading, but now expect others to enter the market.

4.4 Overall Assessment of Progress

The target of 3,000 GWh open interest has not been met, and the reason is that large existing or new OTC hedges have not been turned into futures using EFP or block trades. Nevertheless, a substantial and encouraging amount of progress has been made:

- an exchange was selected, meeting most of the exchange requirements set down by Government;
- four market-making agreements are in place;
- contracts are available, and trading has occurred, in all quarters out to December 2014;
- open interest is growing steadily.

There remains some room for debate about whether the 1 MW, 1 quarter contract size is the optimum, although only smaller generators have expressed any real concern over this.

It appears that the market has reached a point where new players need to enter, and in fact some are preparing to but are held back by reservations about the wide bid-ask spread and pricing efficiency. On the other hand, it would be natural for the major generators to expect support from new players, which would increase trading volumes and open interest, and most likely bring the bid-ask spread down from where it is now.

To move forward, and to meet the 3,000 GWh open interest target in a reasonable time, something needs to change, in particular, new players need to enter the market.

5 Meeting the Government's Requirements

Given our conclusion above, we now turn to the means by which this might best be achieved.

Our approach to making the recommendations in this section is driven by our two key assumptions from section 3.2:

1. the hedge market reforms should enhance competition, in particular, in the retail sector; and
2. in respect of progress on developing the hedge market, time is of the essence.

They are also driven by the recognition that the major generators are effectively being required to provide a hedge market which will, if it achieves its objectives, in the longer term reduce the overall level of vertical integration. This requires a change in emphasis and a change of culture around trading and managing risk within the major generators themselves, as well as new entry into the futures market. A third key driver of our recommendations, therefore, is that the more this process can occur with minimal direct intervention or regulation, the better. As a result, our recommendations are intended to signal the potential for intervention in the market, but provide opportunity for the market to adjust to a lower level of vertical integration with little or no intervention.

In order to demonstrate success and to achieve the Government's objectives, the futures market must have:

1. efficient pricing: evidenced by narrow bid-ask spreads and traded prices which reflect an aggregated view of expected future spot prices; and
2. entry of new players (in particular, one or more retailers and one or more intermediaries): this will demonstrate that the changes to the hedge market are providing open access, and while most large consumers will never wish to trade in futures, they will have the benefit of more competition in the hedge market and access to futures prices through intermediaries or market-makers.

5.1 Options for Improving Performance

5.1.1 The Option of Doing Nothing

Trading volume and open interest have both grown steadily since August 2010, so that doing nothing is an option that must be considered seriously. At the current rate of growth of open interest of about 55 GWh per month, the 3,000 GWh target would be met in about four years time. An increase back to 110 GWh per month would see the target reached in under two years, and if 200 GWh per month could be achieved then the target could be met in a year from now.

Alternatively, existing or new large hedges between market participants could be put through the futures market using EFPs or block trades, and the target would be met virtually overnight.

A significant open interest is required to ensure that major generators have enough riding on futures prices, in terms of daily settlement, to maximise the chances of futures prices being efficient (or at least until such time, if it ever arrives, that the futures market can thrive without market-making). However, based on stakeholder feedback, to attract new players into the futures market, the bid-ask spread needs to come down significantly, preferably to between 1% and 3%. Increasing the open interest while only major generators trade futures may achieve this, since an increase in trading volume should, other things being equal, reduce the bid-ask spread. However, the open interest could hit the target while trading volumes are relatively low, for example if EFPs or block trades are used, so there is no guarantee that the bid-ask spread will reduce.

While in theory, pricing could be efficient even while the bid-ask spread is relatively wide, in reality under these conditions futures prices are likely to exhibit relatively high volatility and are less likely to be efficient.

Doing nothing, and taking a watching brief, could see volumes grow, bid-ask spreads come down, new players enter, further growing volumes, with further reductions in the spreads, the entry of speculators, and so on. That is how a futures market might evolve in an ideal sense, driven initially by the demand for risk management instruments from market participants that have an absolute necessity to hedge.

Alternatively, doing nothing could see modest growth in volumes with bid-ask spreads remaining too wide to attract new players. The market-makers currently have no risk management imperative to drive growth in futures trading, as their risks are managed satisfactorily through vertical integration and in the OTC market. Their incentives are currently much weaker: the threat of regulation.

On balance, we believe the do-nothing option leaves too much to chance, given that time is of the essence and that new players are ready to enter the futures market now (but are unwilling to enter until the bid-ask spread reduces and they are confident there is sufficient market depth).

5.1.2 Reducing Contract Size

Reducing the contract size to either 0.25 MW or 0.5 MW would better cater to the needs of smaller retailers and possibly some smaller generators.

On the other hand, it would take time to implement and has practical difficulties associated with it, not least of which is that the ASX systems do not accommodate decimal places in contract sizes. If the contract size were reduced in the short term, and then it turned out to be too small, reversing the change is a more complex exercise due to the need to aggregate existing contracts.

A watching brief should be kept on the development of the market, and if not satisfactory then reducing the contract size could be considered as a medium priority measure.

5.1.3 Reducing Contract Length

Smaller retailers, in particular, would benefit from having monthly contracts in the medium term (e.g. 3 - 12 months ahead).

On the other hand, introducing more contracts could reduce liquidity in existing contracts.

It may be that monthly contracts could be introduced so that they do not cannibalise liquidity, and this is worthy of further consideration as a medium priority.

5.1.4 Allowing an Intermediary to Take a Market-maker's Role

The Government expects major generators to be market-makers, but there is no reason why a major generator could not engage an intermediary to undertake this role for them, backing off the resulting futures positions with CFDs. This might reduce the overall cost and risks associated with the market-making role.

It appears that most major generators have set themselves up to trade in futures directly, so this type of arrangement may not be necessary, but we see no reason why this should not be permitted if it meets minimum requirements for market-making and suits the major generator(s) concerned.

5.1.5 Disclosure of Market-making Agreements

This would allow public scrutiny of market-making arrangements, which would facilitate and focus debate on the topic, and possibly put pressure on major generators to tighten these arrangements to bring the bid-ask spread down. It would also provide market-makers with assurance that their respective market-making contracts all contained the same requirements.

On the other hand, market-making agreements may change quite slowly, and perhaps not at all. In addition, anonymity is preferable in futures trading, and disclosing these agreements would partially violate that principle.

On balance, we do not believe that disclosure would achieve much in the short term and should be avoided.

5.1.6 Extending the Target Date for Reaching the 3,000 GWh Open Interest

This would allow time for the market to evolve more naturally, and recognises the progress that the major generators have made already. Mandating short term achievement of this target would simply lead to EFP or block trades.

On the other hand, at the current rate of progress 3,000 GWh could take years to achieve, or might never occur if trading were to tail off.

On balance, we consider it worth giving the major generators the benefit of the doubt and allow the target to be met over a longer time, but preferably within the next 18 months, on the condition that liquidity develops in the short term to the point where new players enter (and stay in) the futures market.

5.1.7 Tightening the Minimum Requirements for Market-making

These measures could include reducing the maximum bid-ask spread, compulsory reloading of bids and offers within specified times, and minimum trading volumes. This would force the bid-ask spread to reduce, and create enough depth for new players to enter with a degree of confidence.

On the other hand, major generators may get 'hit' by futures trades that go against them, for example by building up a substantial position in futures that are 'out of the money' (inefficiently priced). In particular, a requirement to reload bids and offers within a certain time could leave market-makers with a risk of exposure to manipulative trading strategies.

On balance, this measure is considered the most likely to change market dynamics, and facilitate new entry in the shortest time of all options considered. The risks around tighter market-making, particularly compulsory reload, are probably quite small given the small size of the market and its relatively specialised nature, but it may be necessary to provide market-makers with a ‘safety valve’ should trading become ‘toxic’.

5.1.8 Mandating Minimum Hedge Volumes

This option would require specified minimum volumes to be hedged by the major generators, and perhaps by others, either through the futures market, the OTC market, or both. The principle behind this intervention is that it forces a minimum level of trading in the hedge market, stimulating demand for hedging products. It would be accompanied by tighter rules around disclosure of hedge data and hedge positions.

However, this is a relatively heavy-handed intervention which might be considered if other measures fail to produce the results expected.

5.1.9 All Hedge Trading Conducted in the Futures Market

Hedge trading would either be undertaken directly in the futures market, or for those not wishing to trade futures it would be done via a futures trader, perhaps an intermediary or a major generator using back-to-back trades. This would automatically put all hedges, directly or indirectly, through the futures market and maximise traded volumes and open interest.

But this is also a relatively heavy-handed intervention which should be considered only if other measures fail to produce the results expected.

5.1.10 Only Allow Hedges to be Sold to Consumers over 10 GWh pa

Securities legislation currently limits dealing in hedges to retailers, generators, ELBs, health boards, members of the Major Electricity Users Group, registered banks, public bodies, consumers using over 10 GWh per annum, and the financial community (banks, investment businesses and large private investors). By mandating all consumers in this category to buy hedges, as opposed to FPVV contracts, the hedge market would expand by up to 3,000 GWh per annum (refer Table 1), increasing the demand for hedges which would hopefully lead to increased demand for futures (mostly via intermediaries, major generators and other futures traders).

However, this would force many consumers out of their comfort zone, place costs and additional risks on those least able to bear them, and could potentially have disastrous consequences. As a consequence, we would not recommend this option.

5.1.11 Allow Futures to be Counted in Assessing Retailers’ Prudential Requirements

All retailers, including major generators, must meet prudential requirements placed on spot market purchasers. The Code currently allows retailers to lodge hedge agreements with the spot market Clearing Manager so that the hedge can be settled through the Clearing Manager, and the effect of the hedge to be taken into account in calculating a retailer’s expected spot market liabilities.

All retailers would benefit, but particularly small retailers, if their net futures position could be taken into account by the Clearing Manager each month when calculating prudential requirements. Futures could never be settled through the Clearing Manager but it may be possible for the ASX[24] to provide the Clearing Manager with each retailer's net futures position each month so that this can be taken into account.

5.1.12 Reduce Information Asymmetries

Information asymmetry occurs when information which is relevant to trading at a material level, is not available to all traders. In December 2010, for example, it became evident that snow pack energy storage (expected to arrive in southern hydro lakes) was likely to have impacted on spot prices, but the information was not widely available. Information asymmetry can lead to market failure and inefficient pricing.

The NZEM is reasonably well served for information, but there are currently three key areas where the market as a whole would benefit from better information:

- snow-pack energy storage;
- the total contract position (retail load plus hedges) of the market: as total contract cover nears demand, spot prices may fall due to generators shaping their offers to cover their contracts at short run marginal cost; and
- fuel prices for generation: gas and coal prices are key drivers of electricity spot prices. Disclosure has improved recently, in particular by Contact Energy, and we expect it to improve further if and when partial SOE sales occur, but there is no guarantee that disclosure will be consistent or meet any minimum requirements.

Some market participants may feel that confidential information is being given away, but thinking only of the development of the futures market, having access to key information is essential.

5.2 Recommendations

Improving liquidity in the futures market is the key to moving forward with the hedge market reforms. While liquidity may improve naturally over time without further intervention, there is no guarantee that this will occur. Time is of the essence, and new players appear to be ready to enter the market when the bid-ask spread reduces and they can be assured of market depth to support trading in reasonable volumes.

5.2.1 Tightening the Market-making Agreements

The most effective way of improving liquidity in the short term is to ensure that the maximum spread allowed in market-making agreements is reduced significantly from where it is now, thus reducing the bid-ask spread seen in the futures market. For example, a maximum spread of 5% would most likely reduce the average spread to between 2% and 3% in the short term. The maximum spread needs to be just small enough to attract new players, and the optimal value is likely to be between 5% at the upper end and 2% at the lower end (the latter could see the bid-ask spread sitting below 1%, which is lower than the average spreads currently seen in the more liquid Australian electricity futures contracts).

[24] Or ASX clearing participants.

Our preferred option is to address the bid-ask spread and market depth directly, by requiring that the market-making agreements in place for the major generators have certain minimum requirements in respect of the daily 20 minute trading window:

- at least one bid and offer to be made on each contract at the start of the 20 minute window;
- bids and offers to be reloaded with a maximum of 60 seconds delay after a trade on front quarters (first 4 quarters), with progressively longer delays on subsequent quarters up to a maximum of 5 minutes;
- a safety valve mechanism to cover the risk of large adverse market movements or even market manipulation;
- the maximum spread to be 5% of the offer price (asking price for contract sales).

The combination of narrower bid-ask spreads and consistently available competitive bids and offers near to, and at the closing of trade each day will help lower the initial margins and help to ensure that daily settlement prices (against which contracts are valued each day) are competitive and efficient.

As these requirements are more onerous than those presumed to exist at present, the Authority should consider increasing the threshold for mandatory market-making to 1,000 MW of capacity (up from 500 MW), with additional requirements around net position, i.e. large net retailers might also need to be excluded.

In the first instance, this recommendation should be discussed with the major generators and it is considered possible to have these requirements in place on a voluntary basis in the short term.

In the medium term, the Code could be modified to require major generators meeting specified criteria to be market-makers, and to ensure that market-making agreements meet minimum specifications. In effect, this would recognise in the Code that the price of being a major generator in the NZEM is a requirement to support the hedge market, in this case by being a market-maker in the futures market.

5.2.2 The 3,000 GWh Open Interest Target

Market-makers are typically required to work on narrow spreads, the size of which may depend on the nature of the commodity or asset being traded. Market-makers are often given incentives to fill this role, and they can profit from the spread by continuously selling at a slightly higher price than they buy at[25]. In most cases, where there are willing buyers and sellers, market-makers do not need to maintain a net position to make a market (although it must be said the market could still go against them for a time), and hence the willing buyers and sellers effectively set the price.

Based on our discussions with consumers, retailers and generators, however, there is the possibility in the short to medium term that additional demand for futures will be driven by hedge buyers, which would cause market-makers to become significant net sellers of futures, as retailers and intermediaries, and possibly one or two large consumers, enter the market. One could expect market-makers to react to this one-sided demand by

[25] In futures markets, buying and selling the same contract on the same day results in a zero position so no profit can be made. To profit from market-making in futures requires more sophisticated strategies which trade other spreads, e.g. across two nodes or across time.

raising the asking price, which in the short to medium term could cause futures prices to over-estimate expected spot prices[26], thus introducing a premium for hedges.

A significant quantity of open interest could reduce the likelihood of a premium developing by partly balancing out the net short positions of market-makers, but this is hard to predict without knowing more details of market-makers' portfolios. We therefore recommend that the 3,000 GWh target for open interest should stand, and that it is reasonable to expect that this will be achieved within the next 12 months.

For avoidance of doubt, it is important to ensure that major generators understand that converting large hedges to futures using EFP, or making large block trades, is an entirely valid means by which open interest can be increased to meet the open interest target.

5.2.3 Futures and Prudential Requirements

To assist small retailers who trade futures, and to partly offset the costs of market-making, the Authority should investigate how a net futures position could as of right be taken into account in calculating prudential requirements, and amend Part 14 of the Code accordingly (Clearing and Settlement).

5.2.4 Information Asymmetries

To help ensure efficient pricing in the futures market, the Authority should investigate if and how the following information could be provided to the market:

1. snow-pack energy storage;
2. the total contract position (retail load plus hedges) of the market;
3. fuel prices for generation.

We understand the Authority will be commencing a project on market information in the near future.

5.2.5 Timing

The immediate step is to meet with the major generators to discuss tightening up the market-making arrangements, with the aim of reducing the bid-ask spread and ensuring adequate market depth in the very short term[27].

Open interest should continue to be monitored and if, at any time within the next 12 months (in particular, just prior to November 2011), it becomes clear that there is a significant risk that the 3,000 GWh target will not be met, or if it is not met after 12 months, then progress may need to be reviewed again. If that is required, then key factors to consider include the progress the futures market has made in two key areas:

1. liquidity, as measured by the bid-ask spread, market depth and resilience; and
2. entry of new players.

For example, if traded volume and open interest have grown significantly from now, and are still growing, and the market is liquid, new players have entered the market, and

[26] In the longer term this is less likely assuming that other hedge sellers enter the market.
[27] We understand, at time of writing, that a meeting was arranged and has taken place.

feedback from stakeholders is generally positive, then the requirement to meet the target could be relaxed.

The other key actions in sections 5.2.3 and 5.2.4, and modifying the Code in respect of market-making, should be progressed as a high priority in wholesale work streams. Items 1 and 2 in section 5.2.7 should also be addressed if and when it becomes clear that there is demand for them.

5.2.6 Risks

There is no guarantee that reducing the bid-ask spread will attract new players, they are not compelled to trade. The bid-ask spread might also need to be reduced for some time before new players enter the market. But if, after a period of months, there has been no new entry, one might have to ask the question: is there a future for electricity futures?

In that case, greater intervention may be required, as outlined in section 5.2.7 below, items 3 through 7, in that order.

5.2.7 Other Options

Other options are listed below in order of priority. Apart from options 1 and 2 below, these should only be pursued if the futures market fails to develop sufficient liquidity within 12 months after implementing the high priority recommendations.

1. Allow an intermediary to take a market-maker's role: this should be permitted upon request, as long as market-making requirements continue to be met.
2. Evaluate how monthly futures contracts could be added without unduly impacting on liquidity in other contracts. This should be undertaken sometime within the coming 12 months.
3. Evaluate a reduction in contract size to 0.25 MW or 0.5 MW.
4. Disclose market-making agreements.
5. Mandate minimum hedge volumes either through the futures market, the OTC market, or both.
6. Conduct all hedge trading, directly or indirectly, in the futures market.

6 Glossary

Bid-ask spread: the price difference between bids offers to sell futures contracts (the asking price) and bids to buy futures contracts. Occasionally referred to as bid-offer spread.

Bilateral: a bilateral contract has two parties to the contract, e.g. buyer and seller of a hedge.

Block trade: an 'off market' futures traded where contracts are trade at a price agreed between buyer and seller (not necessarily the going futures price), and the relevant futures contracts are then created. Block trades do not contribute to settlement (displayed futures) prices, but do add to open interest.

Clearing participant: a member of the futures exchange that clears future contracts (including initial margin, settlement and margin calls) and guarantees performance of contracts.

Code: the Electricity Industry Participation Code.

Contract for differences (CFD): A contract for differences is a type of hedge that contract for which the payout is equal to a quantity in MWh multiplied by the difference between the fixed strike price and a spot price - refer to 7.2 for more details and examples. A CFD is a type of swap.

Cost of liquidity: the cost of providing liquidity in a market, usually measured by the bid-ask spread: a narrow bid-ask spread suggests that the premiums paid by buyers and sellers, in return for being able to trade 'at will', is small.

Daily settlement: every business day the futures exchange calculates the change in a futures contract's value (i.e. its expected payout). For the electricity futures contracts traded on the ASX, the change in value is proportional to the change in the relevant future price, except on the last day of the contract period when it is calculated relative to the average spot price at the relevant grid node for the contract period. Changes in the value of a futures contracts are debited/credited to the contract owner's account with a clearing participant.

Daily settlement price (DSP): the price calculated at the end of each day for use in daily settlement and for settling futures contracts that are held to expiry (on the last day of the futures contract daily settlement is based on the difference between the actual average spot price for the relevant quarter and the previous day's settlement price). The daily settlement algorithm used by ASX is designed to ensure the greatest chance of DSPs being competitive, specifically:

Daily Settlement Price (DSP) will not be generated at levels less competitive than outright orders at market close. For example, DSP will be generated from the last traded price where more competitive than orders at market close, and if the last traded price is outside closing bid-ask spread then DSP will be the extreme of the bid-ask spread closest to the last traded price. In the absence of trades or valid orders DSP will be the previous DSP.

Electricity Authority (EA): electricity governance body established to operate and govern the electricity industry from November 2010.

Electricity Commission (EC): electricity governance body established in 2003 to operate and oversee governance of the electricity industry from March 2004, and subsequently disestablished October 2010 to make way for the Electricity Authority.

Electricity Corporation of New Zealand (ECNZ): an SOE established April 1987 to own and operate the generation and transmission assets of the Ministry of Energy. In July 1994 Transpower was separated out of ECNZ as an SOE in its own right.

Electricity Industry Act 2010 (the Act): contains the latest market reforms and replaces or streamlines many clauses in older acts such as the Electricity Act 1992.

Electricity Industry Reform Act 1998 (EIRA): required ownership separation of lines and energy businesses, placed restrictions on the activities of ELBs, and created three new SOEs from ECNZ.

Electricity Lines Business (ELB): any entity carrying on the business of providing electricity lines (transmission or distribution) services for electricity.

Electricity Supply Authority (ESA): electricity companies that prior to mid 1998 owned lines in their franchise area.

Electricity Technical Advisory Group (ETAG): advisory group set up in 2009 to review the performance of the electricity market and to recommend how its performance could be improved.

EnergyHedge: a hedge market set up and traded by the five major generators late 2004. Disestablished November 2010 to make way for the new electricity futures market.

Exchange for physicals (EFP): an 'off market' futures trade where existing hedge contracts are converted to futures contracts, and the relevant futures contracts are then created. EFP trades do not contribute to settlement (displayed futures) prices, but do add to open interest.

Financial Transmission Rights (FTRs): electricity derivatives whose payout is the difference between two nodal spot prices multiplied by a fixed quantity. The Authority's current proposal is for FTRs which payout on the difference in price between Otahuhu and Benmore (or Benmore and Otahuhu, depending on the direction of the FTR).

Fixed price variable volume (FPVV): an electricity supply contract sold by a retailer to a large consumer, or by a small generator to a retailer or generator, in which any volume of electricity in a period is traded at a fixed price.

Face value: equal to the strike price in $/MWh multiplied by the hedge quantity in MWh. Represents the payout on the hedge if the spot price is zero.

Forward: a forward contract is initiated at one time and performance in accordance with the contract occurs at a later time. The price is set at the time the contract is initiated but both payment and/or delivery occur later. All hedge contracts are types of forward contract, but in the context of hedging with derivatives, forward is often used to refer to CFDs.

Forward curve: a graph, chart or table showing the prices of the most recently traded forward or futures contracts against the period they relate to. In a liquid market where a significant and sudden movement in prices occurs such that the most recent traded price is outside of the latest bids and offers, or where a market is illiquid and trading is infrequent, then bid and offer prices may be used in lieu of recent trades.

Futures: a futures contract is a type of forward contract a type of forward contract traded on a regulated exchange (e.g. the ASX) and which has standardised terms and conditions, a clearing house and clearing participants who guarantee contract performance. Futures contracts are always with the clearers, and any transaction involves one contract to sell and another to buy (i.e. two contracts). Futures are also subject to 'daily settlement' and 'margin calls' and are required.

Government Policy Statement on Electricity Governance (GPS): a statement outlining the objectives and outcomes the Government wants the body governing the electricity industry to give effect to. With establishment of the Electricity Authority, the GPS is no longer necessary and was revoked on 1 November 2010.

GWh: unit of electrical energy equal to 1 GW of power operating for one hour. New Zealand's total electricity demand is currently approximately 39,500 GWh.

Hedge: a hedge is anything that offsets a pre-existing risk. In the context of the electricity market, common forms of hedge include retail load (as a hedge against the volatile returns from generating and selling into the spot market) and all forms of derivative contract.

Hedge Market Development Steering Group (HMDSG): a technical advisory group formed by the EC late in 2004 to "provide advice to the Commission on the development and implementation of a transparent and liquid electricity hedge market".

Initial margin: a specified amount that is deposited into a margin account with a clearing participant when a futures contract is bought or sold.

ISDA agreement: a standard agreement for swaps and options, developed by the International Swap Dealers Association.

Liquidity: There is no single definition of liquidity, but a particularly comprehensive and useful definition is given in a paper sponsored by the Bank for International Settlements (Locke and Sarkar 2001) which describes liquidity in three dimensions: tightness, depth and resilience. Tightness is how far prices diverge from mid-market prices, and is measured by the bid-ask spread, i.e. the price difference between bids offers to sell futures contracts (the asking price) and bids to buy futures contracts. Depth denotes the volume of trades possible without significant movement in price, and resiliency refers to the speed with which imbalances in trading are adjusted.

Locational price risk (LPR): the volatility in the price difference between specified nodes on the grid.

Maintenance margin: when the accumulated daily settlement amounts on a futures contract reduce the margin account balance below the maintenance margin, a margin call is made and the margin account balance must be brought back up to the initial margin.

Market-maker: a futures trader that simultaneously makes bid and offers to buy and sell futures contract with a narrow spread between the two prices, in order to stimulate trading.

Margin account: an account established with a clearing participant prior to buying or selling a futures contract.

Margin call: if the daily settlement process leads to a futures contract owner's account with a clearing participant falling below a minimum value called the maintenance margin, the clearing participant will make a margin call requiring the contract owner to deposit funds to bring the account back up to the initial margin. The amount of the deposit is called 'variation margin'.

Ministry of Economic Development (MED): policy agency for electricity.

New Zealand Electricity Market (NZEM): Refers to the wider electricity market, not to be confused with the voluntary market which was in place from October 1996 to February 2004.

Open interest: at a defined point in time, this is one half of the total number of futures contracts (or the equivalent volume in energy terms) that have been bought or sold but have not yet settled. This excludes contracts that were bought or sold, but which have subsequently been offset or 'closed out' by selling or buying, respectively a contract for the same contract period. As futures positions are often closed out[28], the open interest is almost always less than the total number of contracts traded but not yet settled.

Option: confers a right to buy ('call' option) or sell ('put' option) an underlying commodity on or before a specified exercise date. The buyer of the option pays the seller a fixed premium or option fee. In the case of electricity an option would typically give the buyer the right to receive a cash payment rather than physical delivery of electricity. A 'swaption' is an option to buy or sell a swap (or futures contract). 'European' options can only be exercised n the exercise date, but 'American' options can be exercised on any date up to and including the exercise date.

Over the counter (OTC): refers to hedge transactions outside of exchanges, typically by negotiation between two parties. Also refers to the total market for non-exchange hedge transactions.

Planned Outage Co-ordination Process (POCP): contributed to by Transpower and market participants, allows publication of outage information on a public web site.

Spread: a generic term referring to a difference in price, with meaning depending entirely on context. For example, it could refer to the bid-ask spread, or it could refer to the difference in price between two non-identical (but usually similar) traded assets or commodities. Examples of the latter would be the spread between the prices of electricity futures contracts traded at Otahuhu and Benmore, or the difference in the price of electricity futures contracts at Benmore for two adjacent quarters.

Strike price: the fixed price of a hedge.

Swap: A derivative contract in which a variable (spot) rate is swapped for a fixed rate.

Trading period: the spot electricity market operates on a half hourly cycle, 48 times per day (two more or less on daylight saving changeover days) and each half hour is referred to as a trading period. Spot prices vary by trading period and also across the grid.

Variation margin: refer to 'margin call'**.**

Virtual asset swaps (VAS): large hedge contracts traded between Meridian Energy and Genesis Power, and between Meridian Energy and Mighty River Power, pursuant to the latest market reforms.

7 Appendix 1 - Forward and Futures Contracts

Using simple examples, this Appendix briefly explains how spot exposure may arise, and explains how forward contracts (CFDs) and futures are used to hedge this exposure, with the emphasis on the differences between CFDs and futures.

7.1 Spot Exposure

There are three ways in which a spot exposure typically arises: as a generator selling into the spot market, as a retailer buying from the spot market, or as a larger consumer buying from a retailer.

[28] In futures markets around the globe, something like 90% of futures contracts are never held to maturity.

The Code requires that all generation is sold into the spot market, and associated with this is a revenue stream which, in each half hourly trading period of the market[29], is equal to the spot price (at the node on the grid where the generator injects power onto the grid) times the total injection. This revenue stream therefore changes as the volume of injection changes and as the spot price changes.

A retailer must purchase its electricity from the spot market[30] in each half hourly trading period of the market, at the spot price (at the node on the grid where the electricity is delivered). The cost of purchases therefore changes as the volume of purchase changes and as the spot price changes.

A larger consumer may also elect to purchase electricity at spot price from a retailer. The retailer, in turn, purchases this electricity from the spot market as described above. The consumer's electricity cost is mostly a pass-through of the retailer's cost of purchases from the spot market on behalf of the consumer, but there is usually a small accompanying fee which covers other market costs[31].

7.2 CFDs and Futures

Given a spot exposure, most organizations undertake hedging in some form, for example using CFDs. CFDs are traded by arrangement between the two parties transacting the hedge, who then sign a hedge contract. Amongst other things, before parties sign the contract they will consider the credit risk associated with the other party, i.e. the risk that the other party will not meet their obligations if and when required to pay out on the hedge.

A CFD is a type of hedge contract for which the payout in a trading period is equal to a fixed quantity in MWh multiplied by the difference between the fixed 'strike price' (also called the hedge price) and a spot price:

payout = hedge quantity × (strike price - spot price)

where the hedge quantity has units of MWh and the prices are in $/MWh.

The spot exposure in a trading period for a retailer or consumer is a *negative* cash flow given by:

quantity purchased × spot price

The spot exposure for a generator in a trading period for a generator is a *positive* cash flow given by:

quantity purchased × spot price

[29] The spot electricity market has 48 trading periods in each day (except on the daylight saving changeover days). Spot prices are different in each trading period.
[30] Or from another retailer.
[31] In a FPVV contract the other market costs are typically bundled into the fixed energy prices.

As long as we are careful about whether we are referring to a spot purchaser (retailer or consumer) or a spot seller (generator) then we can study both situations quite neatly by writing the total cost or revenue in a trading period as

Total cost/revenue = quantity purchased × spot price + hedge quantity × (strike price - spot price)

For example, suppose that in a particular trading period the spot price is $80/MWh, the quantity purchased is 0.5 MWh (i.e. the average load during the trading period is 1 MW) then the spot exposure is 0.5 × 80 = $40. If the price rises in the next trading period to $100/MWh with the same load then the spot exposure is 0.5 × 100 = $50. If the price falls in the next trading period to $60/MWh then the spot exposure is 0.5 × 60 = $30.

If there is also a 1 MW hedge in place (hedge quantity 0.5 MWh per trading period) with strike price $80/MWh then the total cost/revenue in each trading period is:

1st trading period: $40 + 0.5 × (80 - 80) = $40
2nd trading period: $50 + 0.5 × (80 - 100) = $40
3rd trading period: $30 + 0.5 × (80 - 60) = $40

What the hedge has done is offset the variability in the spot exposure, thus smoothing out the cost or revenue. In reality, complications arise, notably that the spot price in the CFD calculation may be different to the spot price in the spot exposure calculation, for example the spot exposure may be at the Huntly node south of Auckland, with the CFD spot price at Otahuhu. Similarly, the quantity used in the spot exposure calculation rarely exactly equals the hedge quantity. However, these complications can generally be managed by attention to the details of hedging strategy, so in the interests of simplicity these complications won't be considered in this Appendix.

A CFD is generally bought or sold to cover many trading periods, and the example we will use is a 1 MW CFD with strike price of $80/MWh which covers every trading period in the quarter ending September 2012, i.e. it covers the months of July, August and September 2012. A key feature of CFDs is that they are settled monthly, so even if the CFD was bought or sold months or years prior to the quarter, no cash changes hands until sometime in August 2012. During this month, the spot exposure will also be settled.

For example, if the average spot price in July 2012 is $70/MWh then the hedge settlement is 31 days × 48 trading periods × (80 - 70) = $14,880 and this amount is pad over some time in August 2012.

On the other hand, consider an ASX futures contract which is bought or sold in October 2011 to cover the September 2012 quarter, and let's suppose it's price is once again $80/MWh. For this to happen, there must be a buyer and a seller for the futures who are happy to trade at a price of $80/MWh. A key difference to CFDs, however, is typically that neither party knows the identity of the other[32].

[32] Except in the case of EFPs or block trades identities may be known.

The buyer and seller can transact independently on their own behalves, or they can work through their respective brokers who are members of the ASX. Either way, they also have to arrange a clearing participant who is a clearing member of the ASX. Together with the ASX's clearing house and other clearing participants, clearing participants guarantee that the futures contracts will be honoured and thus eliminate credit risk from futures trading.

In actual fact, there are two futures contracts involved in this trade (and in all futures trades): the seller of the futures contract sells it to their clearing participant, and the buyer of the futures contract buys it from their clearing participant. The exchange's information systems facilitate the job of initiating these trades when there is a futures buyer and futures seller who are prepared to transact at the same price.

Once the futures trades have been done, they are subject to the process of 'daily settlement'.

Both the futures buyer and the futures seller must deposit an amount known as the 'initial margin' into a 'margin account' with their respective clearing participants. The initial margin is calculated by the ASX and represents the worst case one day change in the value of the futures contract. Interest is payable on any balance in margin accounts.

Let's suppose the initial margin is $20,000 and, for the sake of simplicity, we'll focus on the party that sold a futures contract. Each day after the futures contract is traded it is revalued using the change in the futures price. For example, suppose the futures price for this contract falls to $78/MWh the day after it is sold (we're assuming here that the market now expects the spot price in the September 2012 quarter to be $78/MWh instead of $8/MWh), then the change in the contract's value is equal to the total quantity (1 MW for the entire September 2012 quarter) multiplied by the change in futures price:

change in value = 4,418 half hours × (80 - 78) = $8,836

This amount is added to the seller's margin account which now contains $28,836.

However, on day three the futures price rises back to $80/MWh and so the next daily settlement reflects a reduction in the value of the futures contract:

change in value = 4,418 × (78 - 80) = -$8,836

and the total in the margin account falls to $28,836 - $8,836 = $20,000.

On day four the rise in futures price continues to $82/MWh and so the next daily settlement reflects another reduction in the value of the futures contract:

change in value = 4,418 × (78 - 80) = -$8,836

and the total in the margin account falls to $20,000 - $8,836 = $11,164.

At this point we have an issue: the clearing participant requires that the balance in the margin account never falls below the 'maintenance margin' which we'll take as 75% of the initial margin or $15,000. The futures seller is then issued a 'margin call' which must be paid that day, and the amount is just enough to bring the balance in the margin account back to the initial margin. This amount is known as the ‘variation margin’ which is in this instance $20,000 - $11,164 = $8,836.

This process of daily settlement continues until one of two things happens:

1. the contracts reaches it expiry date at the end of the September 2012 quarter; or
2. the futures seller *buys* a futures contract for the September 2012 quarter.

In the first case above, when a futures contract is held to its maturity date, then on the last day of daily settlement it is calculated using the *actual spot price* averaged over the entire September 2012 quarter: this ensures that there is a link between the futures price and spot prices.

In the second case above, the clearing participant and the ASX exchange recognise that the seller has ‘offset’ (or ‘closed out’) their original contract and the combined daily settlement on the two contracts will always result in a net change of zero in the margin account associated with the two contracts. In other words, buying the September 2012 futures effectively eliminates any further changes in value with the original contract for the September 2012, and from this point onward the two contracts are effectively ignored, which is to say that no further settlements occur.

From this example, we can see that daily settlement means that cash may be gained or lost (through margin calls) on every day that a futures contract is held. However, if the contract is held to maturity, then there is no further cash to be exchanged after this date.

It can also be shown that the net cash flow on the futures contract is exactly equal to the equivalent 1 MW CFD for the quarter: the difference is in the timing of the cash flows.

8 Appendix 2 - Literature Review

There is no single definition of liquidity, but a particularly useful definition is given in a paper sponsored by the Bank for International Settlements[33] (Locke and Sarkar 2001) which describes liquidity in three dimensions: tightness, depth and resilience. *Tightness* is how far prices diverge from mid-market prices, and is measured by the bid-ask spread. *Depth* denotes the volume of trades possible without significant movement in price, and *resiliency* refers to the speed with which imbalances in trading are adjusted.

By this definition, a liquid futures market would exhibit a narrow bid-ask spread. There would also be a relatively large number of orders to buy and sell which are able to come quickly to market, and which have bid and offer prices close to the latest traded price. If some shock occurred which caused a large volume of trading to occur particularly quickly, with a consequent movement in price, then a resilient market would return relatively quickly to a state where the bid-ask spread was narrow and there were a large number of trades waiting to be fulfilled at prices near traded prices.

History has proven that it is difficult to predict the success of new futures contracts (Brorsen and Fofana 2001) to the extent that two thirds to three quarters of all new futures contracts fail to attract sufficient volume of trading to be profitable for the

[33] The BIS can be thought of as the bank for central banks.

futures exchange. For example, of 54 financial futures contracts introduced in the US in the period from 1984 to 1986, 31 (57%) failed prior to December 1996 (Jeong 1998).

According to one study, “contracts based on metals had the highest survival rates while contracts based on energy had the lowest” (Penick 2004).

Prior to 1986 the futures literature generally concluded that success of futures contracts is too difficult to predict (Jeong 1998) but a seminal paper from the Salomon Brothers Center for the Study of Financial Institutions (Black 1986) argued that volume of trade and open interest were influenced by a few key variables:

- cash market size: a large cash market often goes hand in hand with more buyers and sellers who need to hedge cash market risks, or who may wish to speculate in futures;
- risk-reduction ability of the contract: a futures market that allows hedgers to accurately offset their cash market risks is more likely to succeed;
- cash price variability: when prices in the cash market are more volatile then there is greater need to hedge cash market risks;
- liquidity costs: usually measured by the bid-ask spread, such that if this is narrow then the premiums paid by buyers and sellers (the cost of liquidity), in return for being able to trade at will, is small.

Subsequent work has argued that an active cash market is a prerequisite for a successful futures market, and that trading volume and open interest are impacted negatively by buyer concentration and vertical integration, but positively by cash price volatility, liquidity cost and homogeneity of the underlying product (Brorsen and Fofana 2001).

A number of authors have concluded that ‘market microstructure’ can impact on liquidity. For example, a simulation study found that liquidity is affected by traders’ sensitivity to short-term price movements, their degree of risk aversion, and their confidence in their own forecasts about prices (Locke and Sarkar 2001) and the authors concluded that, to enhance liquidity, a number of factors could be manipulated, including:

- transparency generally improves the functioning of markets (while preserving anonymity);
- heterogeneity in market participants’ behaviour, reflecting different transaction needs and investment horizons, should enhance market liquidity.

The “ready availability of a custom-tailored forward market” (i.e. an active OTC market) has also been identified as a factor which can contribute to the failure of futures markets (Moulton 2005). This author states that the continued success of a futures market will “hinge on attracting the right mix of investors to ensure appropriate risk transfer” and that the market needs to reward speculators for taking positions to “help smooth hedgers’ desires for trade”, otherwise hedgers may prefer to trade in the OTC market.

In many electricity markets there is relatively little secondary trading activity, and growth in volume is slow. At least one author has speculated that this may be due to the collapse of Enron[34], but also identified lack of competitiveness and the market power of generators as factors which increase risk for speculators in secondary markets. A high degree of regulatory risk may also make the risks of secondary electricity trading too great for speculators (Anderson, Hu et al. 2007).

In fact, in February 2002 NYMEX delisted all of its electricity futures products due to lack of trading, and the Chicago Board of Trade and Minneapolis Grain Exchange suspended all trading in electricity futures (EnergyBusinessReports.com). This report also identified barriers to secondary trading in the US including a legacy of vertical integration, regulations that are still evolving, the unique combination of characteristics of electricity as a commodity (instantaneous delivery, non-storability, an interactive delivery system, and extreme price volatility), the complexity of spot markets (which is not conducive to participation by players from outside the electricity industry), lack of transparency, the difficulties analysts have in modeling electricity derivative instruments, and credit and default risk.

Market microstructure has received some attention in the literature including the impact of contract size. If size is too large then it may prohibit small speculative traders from entering the market and prevent some hedgers fine tuning their hedged positions. But if it is too small then it will increase transaction costs for market participants (Bjursell, Frino et al. 2010). Electricity futures contracts all over the world appear to be 1 MW in size, with a few examples of larger contracts, and no studies of contract splits in electricity could be found. An earlier study (Karagozoglu and Martell 1999) found that greater liquidity is associated with a smaller contract size after controlling for other factors. However, Bjursell et al. note that in respect of futures markets for financial products, contract splits have been associated with higher volumes in some cases, although in one case a reverse split (increase in contract size) initially saw a fall in trading volume but then volume had increased after three years. They conclude that getting the contract size right is important.

While liquidity in futures markets has received little attention, “liquidity in electricity futures has been virtually neglected” (Gross 2006). Previous research indicated that the cost of liquidity (bid-ask spread) and volume are generally negatively correlated (i.e. other things being equal, bid-ask spread tends to fall with volume), and that cost of liquidity and volatility are generally positively correlated (bid-ask spread increases with volatility). The authors studied the NYMEX Palo Verde futures contract, introduced March 1996, and showed that the bid-ask spread actually increased with volume. However the results were inconclusive because volatility also increased substantially during the period of the study.

Market-makers may act on an entirely voluntary basis purely for profit, or they may be contracted to provide liquidity by offering to buy and sell within tight limits. Voluntary market-makers can be thought of as “sellers of options to be adversely selected” (Easley, López de Prado et al. 2011). When the flow of orders goes against voluntary market-makers, they will tend to widen their offered spreads.

Studies of financial futures markets in China show that voluntary market-makers (scalpers) are attracted to market liquidity as well as to their realised spread, and that

[34] Enron collapsed in 2001 after which systematic accounting fraud was revealed. However, during the 1990s was highly active and innovative in secondary energy markets.

non-scalper trades are the source of price volatility (Liu, Williams et al. 2001). The authors describe how scalpers trade frequently during the day and rarely hold overnight positions, and in doing so allow “urgent buyers and seller to trade at low cost”.

These papers suggest that electricity, being what it is, may require market-making agreements with relatively tight conditions to ensure that liquidity develops (or, equivalently, that the cost of liquidity is not a barrier to participation).

In addition to providing a means for hedgers to manage risk, forward and futures markets also play a key role in signaling price expectations to the wider market.

Because electricity cannot be stored economically, classic methods of valuing forward and futures contracts cannot be applied, which leads to the result that the price of a future contract (at the time it is bought or sold) is equal to the expected spot price at the time the contract matures (Hull 1989; McNoe 1997): $F^T = [S^T]$ where F is the contract strike price, S is the underlying spot price, and T is the future time that the contract matures.

However, empirical studies have given varied results. A study of electricity futures listed on the European Energy Exchange (refer section 3.3) found that futures prices were subject to a positive risk premium, which exhibits significant daily variability (Wilkens and Wimschulte 2007).

If demand is equal from hedge buyer and sellers, then we expect F = E[S]to hold, but it can be postulated that if demand for futures exceeds supply then a risk premium may be present (Gjolberg and Brattested 2011). The authors reviewed the literature around commodities and energy markets (e.g. petroleum futures) including electricity, and found some studies that found no risk premium, some with a risk premium and some with evidence of market inefficiency (which is not the same as a risk premium). In a study of futures contracts on Nord Pool, they found that futures prices were upward biased from 1995 to 2008 by 7.4% - 9.3% on a monthly basis. Due to its large magnitude, plus the fact that the errors did not vary by season, they concluded that it is hard to explain this bias as a risk premium only and so may be taken as evidence of market inefficiency. The authors do not give any view or guidance on what might be the cause of the inefficiency, although they do ask whether it is rational to expect further price increases when prices are already high and “empirically tend to revert from unusually high levels”.

9 Appendix 3 - Feedback from Stakeholders

Small Retailers

Other things being equal, small retailers would prefer a smaller contract size (but no smaller than 0.25 MW), but four of the five felt that by the time a small retailer grows to the size where they would consider buying futures to hedge their risks, they can live with 1 MW. Monthly contracts spanning the first six months were suggested as being a possible addition to the futures contracts which would assist small retailers customise hedging to their load profiles.

One retailer would like to see futures trading at Whakamaru.

The immediate concern for this group is the development of liquidity, which would give them confidence to buy futures. One made the comment that they would not like to see further discussion on contract size delay efforts to develop liquidity.

But the biggest concern for this group, even once liquidity develops to a point where they would trade, is that they can access reasonable prices (i.e. efficient prices reflective of future spot price expectations).

Small Generators

Small generators often own only one generating station, or their stations may be run-of-river hydro or a wind farm. They are less likely to hedge in the conventional sense (i.e. using hedges with fixed volumes) and instead prefer arrangements which are "generator-following", i.e. the hedge quantity always equals the generation output[35]. This type of arrangement protects them in periods when the spot price could be very high, but they might not be generating (due to lack of water or wind, or to an outage). Other smaller generators have joint venture arrangements with the major generators and access risk management instruments through them.

Only one small generator indicated an interest in following up on trading futures, but indicated that they would only do so since they have a large storage lake (and would not trade if they were all run-of-river).

Prudential requirements are a major source of risk and concern for retailers, and at least one small retailer expressed the view that futures positions should be taken into account in calculating Prudential requirements.

Large Consumers

Large consumers are generally reluctant to consider trading in futures because of the requirements around daily settlement and margins calls, which they see as imposing operational costs exceeding the benefits of buying futures (as opposed to buying hedges in the wider hedge market), and the general need to monitor the futures market on a regular basis. OTC hedges are preferred by most because they are easier to deal with. Price certainty is key for many, although efficient prices are also a concern.

Only a handful of the largest consumers are likely to trade futures, and these consumers are either still trying to understand how futures work, or are waiting until liquidity develops. None of those interviewed questioned the contract size and one commented that any smaller than 1 MW would be "hard work".

In summary, most consumers don't have the skills and resources to traded futures, and don't see the need as long as they can obtain efficiently priced hedges in the OTC market.

Financial Entities

A number of financial entities are actively trading or brokering Australian electricity futures on ASX and are interested in trading New Zealand electricity futures if they can see that the volume of trading they could undertake represents a viable opportunity, and at least one has all of the internal and external approvals required to trade.

[35] Which is equivalent to a fixed price variable volume arrangement.

Those that see the potential opportunity, however, are still not trading primarily because the bid-ask spread is too wide, and because they don't sense enough depth in the market to support the volume of trading they might wish to undertake, or to allow positions to be closed out reliably.

Financial entities are not interested in contract sizes of less than 1 MW as they claim these will be too costly to process.

One entity noted that for hedgers to access futures prices via intermediaries (in the back-to-back arrangement described in section 3.4), hedgers will need to interact with the hedge market in a different way. For example, an intermediary will only be able to hold a price for an OTC hedge while the relevant futures price remains table, perhaps only during the 20 minute period each day when market-makers are active. This will require hedgers to be prepared to commit to the OTC trade in advance (e.g. within specified price limits) or during the 20 minute trading period.

Major Generators

In addition to interviewing stakeholders, we were with copies of responses from the major generators to the Authority's request to demonstrate the level of commitment to achieving the Government's objectives for a liquid hedge market.

The responses indicate a substantial commitment to making the futures market work, including:

- selecting ASX as the trading exchange;
- entering into market-making agreements with the ASX (four out of five);
- application of new and existing resource to futures trading including personnel, working capital and trading systems;
- active participation in the ASX User Group;
- developing and/or executing new OTC contracts which either reference or back-to-back futures contracts.

Some major generators expressed disappointment at the lack of participation by other parties including larger consumers, and suggested that an assessment of performance in setting up the new futures market should start with why others have not started trading.

One major generator noted concern over the contract size of 1 MW, the costs and risks of the requirement to be a market maker including the current high initial margins.

Concerns were expressed over the impact that 26th March has had on futures trading, by creating uncertainty over spot prices and the regulatory response.

There was also a view expressed that performing EFPs or block trades just to achieve the 3,000 GWh target would be a cynical and costly move which would not go anyway to creating liquidity[36].

[36] Based on current initial margins, the 600 GWh of current open interest represents an investment of $10 million (on which interest is paid) and 3,000 GWh of open interest would represent over $50 million.

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