MDAG – Price Discovery with a 100% Renewables Wholesale Market

Wholesale risk management practice trends in the NZ electricity market, and prospects for a high-renewables future.

October 2021

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Contents

[1] The author is grateful for the comments received from MDAG chair and members, and Electricity Authority staff.

1 Introduction

As part of MDAG's wider problem definition workstreams, MDAG asked Stephen Batstone of Wayne Manor Advisory to assess participants' current and expected risk management capability transitioning to, and operating in, a 100% renewable world.

The ability of market participants to prudently manage risk is critical to the ability of participants to allocate risk efficiently (the "completeness" of markets for risk). This in turn underpins confidence in the market, efficient investment in resources (generation, storage and demand response), and enables the best trade-off between affordability, security of supply, and environmental outcomes.

Our approach was to combine quantitative evidence (e.g., time series of market data), to the extent it is available, with qualitative surveys and expert advice to provide an overall commentary on how different categories of market participants (independent retailers, commercial/industrial users, vertically integrated generator retailers) have matured, and are maturing, in their risk management, and their expectations of the future.

2 Context

2.1 Market design

Whether market participants would properly cover their risks (particularly dry year risk) was a critical issue in the early stages of the market's design. In changing from a traditional centralised risk management scheme[2], a critical design issue was:

> *"how to best create a commercial market framework within which individual parties, bearing their own financial risks, can make their own decisions so as to get new investment in either efficiency, or supply, at the lowest overall cost, not too late to risk shortages, nor too early or too much to cause oversupply"[3].*

It was agreed that the market approach would require a system of commercial incentives and accountability that[4];

- respected the physical realities of the system operation,
- allowed customers to contract with competing generators for the provision of reserves to provide the level of security that they want,
- ensured that generators are accountable for failure to maintain the promised reserves or supply reliability,
- avoided the risks some parties will "free-ride" on the back-up reserves paid for by others,
- while at the same time allowing a sharing of reserves between parties to take advantage of diversity in demand and supply availability.

It was agreed that the mechanisms achieving this would involve uncapped spot pricing and firm contracting[5].

This would result in market participants being exposed to a varying spot price which itself reflected the underlying physical supply – plant, fuel and transmission – and would include "very infrequent periods of high spot prices in abnormally dry years"[6]. The risk of wholesale buyers failing to

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[2] ECNZ aimed to maintain sufficient reserves to ensure that "normal" demand can be met in a "1 in 20" and then (from 1993) a "1 in 60" dry year inflow situation. These medium term reserves were supplied as a "common good" by ECNZ with the costs being recovered from all customers through a "pool price margin" (in other utilities the costs are often recovered through a "capacity payment"). This was charged irrespective of the level that of security that customers want or need. ECNZ's spot prices were determined a week ahead and capped at no more than the cost of oil fired generation (around 15c/kWh), so prices could not rise to reflect the full risks of shortages in a dry year shortage situation

[3] "Managing 'Dry-Year' Risk in a Fully Competitive Market: Issues and Option", Report for Officials Committee on Energy Policy, John Culy, NZIER, May 1995, p8

[4] Ibid

[5] Ibid at p9. Further – "Demand bidding, uncapped spot prices, security hedges, firm financial contracts, and capped financial contracts provide the mechanisms necessary to manage security of supply in a competitive market environment. Customers can purchase firm contracts or security hedges to cover their firm or essential demands and capped hedges to cover discretionary or interruptible demand. Generators sell firm contracts for their reliable supply, security hedges for firm back up capacity, and capped hedges at a discount for unreliable supply capability. The uncapped spot pricing regime provides the powerful incentives for generators who have issued firm contracts or security contracts to manage and maintain their plant and reserves to a very high standard. It also provides very strong incentives for customers to offer demand bids to ensure that their load does not exceed the level of their firm contracts and security hedges" – see Ibid at 5.3 on p12

[6] Ibid, p5

adequately cover their supply exposure was a particular focus in deciding whether or not to go with an energy-only market:

> *"The prime potential concern is that, for a variety of reasons related to the risk of government intervention, retail competition, etc, wholesale buyers may have inadequate incentives to purchase a firm supply contracts or security hedges from generators to cover the "essential demands" of their customers, and that without firm supply contracts generators will not be able meet the full costs of investing in and maintaining adequate back up reserves and hence "security of supply" will fall to unacceptable levels."*[7]

Several reasons were put forward for this concern, including that[8]:

- Wholesale buyers may not have the necessary sophistication to evaluate the risks and hence will not fully recognise and be prepared to pay to avoid them because they are so infrequent (being less than one year in 10).
- Even if they do recognise the risks, there is a concern that wholesale buyers may be reluctant to enter firm contractual commitments in the wholesale market because they;
  - have the perception that, should a crisis arise, a future government will intervene to limit spot prices and to provide a "fair share" of the power even if they don't have appropriate commercial contracts,
  - are unable to get medium or long term contracts with end use customers and they fear of being undercut by imprudent or "fly by night" energy traders carrying lower levels of cover who may simply go bankrupt if there is a crisis,
  - can avoid the financial risk during dry years by restricting supply to their "captive" small customers without needing to financially compensate them because small customers are unable to assess the dry year risk and/or there is insufficient retail competition at this level.
- Even if the risks are fully recognised and accounted for that the risk to the economy overall is greater than the sum of risks to the individual wholesale buyers.
  - This might occur if lack of retail competition or limited corporate liability means that wholesale buyers take the dry year "security" risks less seriously than their end customers would, given the opportunity.
  - Alternatively it might occur if there are external flow-on effects associated with a "shortage" event, such as an impact on New Zealand's reputation, currency etc.

It is interesting to observe that some parties make the same claims in relation to the wholesale market 25 years later.

The Government of the day considered a range of options to mitigate the risk of market participants failing to adequate cover their risks, including a mandatory "security hedge" regime[9] (which would have required retailers to be hedged to ~95% of expected demand), a prudential management scheme, compulsory contracting, pool price caps and administered capacity pricing.

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[7] ibid, p5

[8] Ibid at p14

[9] Ibid and described more fully in "Mandatory Security Hedges: Implementation Issues", and in The Value Implications of Dry-Year Risk Management Regimes", both Report to the Officials Committee on Energy Policy, John Culy, NZIER, May 1995

Weighing the pros and cons of each option relative to the nature and degree of the risk, it was agreed that a “security hedge” regime was not required on the basis that “[t]he transition to a fully competitive market was likely to be gradual, which made it possible to allow the electricity pool, in conjunction with market participants, to develop appropriately flexible rules to deal with the potential concerns if they emerge as the level of competition in the market increases over time through new entry or further disaggregation”[10]. As entry gradually occurred, and competition increased, market participants were expected to gain “the experience and skills necessary to assess the risks, [and] the Government should, hopefully, have gained a track record of allowing the market to work even in times of system stress” amongst other factors, such as a significant increase in demand-side responsiveness, flexible and interruptible tariffs, improvement in metering technology which would allow end users to “better judge both the wholesale risks and the financial "reliability" of the alternative retailers.”[11]

The purpose of this report is to assess how the capacity of wholesale buyers and sellers to manage risk has developed relative to the expectations and policy objectives of the energy-market market design, and how well participants’ risks management capability is likely to further develop to deal with the change in risks expected in the transition to, and operation of, a 100% renewables world.

2.2 Outcomes 1996 – 2010

Our subjective judgment is that the transition to this fully informed risk management regime probably occurred over a much longer period than the original designers expected. With the advent of the ECNZ “babies” in 1999, some new market participants were not able to accurately assess their inherited hedge position in real time for a number of years. At the start of 2001, market participants had very little real-world experience of the “very infrequent periods of high spot prices in abnormally dry years” that Culy’s 1995 paper foresaw. But over the next 7 years, three prolonged low inflow periods[12] provided the first dataset on the likely level of prices in “dry years”, the first of which resulted in the exit of On Energy, the largest non-vertically integrated retailer[13] ever seen in the NZ market, due to financial pressures brought about by insufficient hedging.

Following the exit of On Energy, by far the main risk management tool in the market in the first decade was vertical integration, in the 5 largest generators, with adjustments made at the margin via inter-generator contracts between these entities. From a risk management perspective, vertical integration is equivalent to a set of long-term flexible hedge contracts between retail and generation.

In the period 2000-2010, there was an attempt at creating a transparent forward curve (Energyhedge) between the major generators to provide some transparency of the expected cost of electricity. In parallel, efforts were undertaken to educate major users on price risk, understanding the value of energy risk management (in addition to procurement) and the benefits of contracts for differences for, amongst other things, preserving spot market signals for demand response.

A 2006 report from the Electricity Commission’s Hedge Market Development Steering group identified the following five problems with risk management:

i. Lack of robust information

[10] Ibid at p22
[11] Ibid at p23
[12] One combined with reduced availability of gas and coal.
[13] To be fair, On Energy did have operational control over TCC, however the capacity of that plant was far exceeded by its retail book.

ii. Lack of confidence in competitiveness
iii. Lack of instruments to manage locational-based price risk
iv. High participation and transaction costs
v. Lack of understanding of electricity price risk

As will be outlined below, some of these problems still exist (to different degrees). That said, the package of initiatives proposed by the HMSDG group[14] have all been implemented, and some went much further than proposed (e.g., the development of the FTR market, and the replacement of EnergyHedge with a futures exchange).

However, by 2010, improvement in demand side responsiveness (outside public conservation campaigns) and tariff flexibility only materialised in a small number of isolated instances. In terms of retail competition, only two truly independent retailers (that did not have generation in their portfolio) had emerged [15]. A major turning point for retail competition was the introduction of the ASX and efforts to stimulate retail competition at the turn of the decade.

In considering the question of market participants ability to adapt as we move towards 100% renewables, the analysis below focuses on the most recent decade. This is not to say that the market didn't adapt (it was, in fact, the opposite), rather that significantly more information is available for the period 2010 onwards.

3 Analysis - General Market Trends

3.1 Range of risk management tools and capabilities

Below we will refer to a range of risk management tools, products and policies that are used by electricity industry participants. While not a comprehensive taxonomy, we provide here a brief description of these

Risk management products

Risk management products (usually abbreviated to "contracts" or "hedge products") are traded between participants in one of two ways:

- **Over the counter (OTC)**: these are bilateral negotiations and discussions between buyer and seller. The OTC "market" allows the greatest degree of customisation of the underlying product, although the final form of the agreement is typically based around the International Swap and Derivatives Association (ISDA) standard agreement, with a schedule describing the product itself. The agreements will include credit conditions which must be met e.g., a letter of credit, a minimum credit rating etc.
- **Traded on the Australian Stock Exchange (ASX)**: Futures products are highly standardised hedge products with no customisation allowed beyond the products listed on the exchange (see below). These products are traded anonymously on the exchange in a similar way to equities on a stock exchange. The key difference between OTC and futures exchanges is that in futures exchanges, credit is handled by the exchange through the posting of initial

[14] These were: (i) compulsory publication of key terms and conditions of contracts traded, (ii) EnergyHedge to continue to develop its services, (iii) development of a locational price risk management mechanism (iv) development of a model master agreement, (v) centralised publication of planned outage and fuel stock information by the Commission, (vi) promotion of education around purchaser risk management and (vii) a regular survey of electricity market participants to ensure improvements in hedging are on track.
[15] emi.ea.govt.nz, Market share trends report accessed September 2021.

margins and variation margins[16], rather than credit ratings or other requirements. As long as a buyer or seller can fund the initial margin and variation margins through time, they can trade.

Traded risk management products shown below and discussed with participants include:

- **Contracts for Differences (CfDs)**: contracts for a given quantity which settle based on the difference between the agreed (fixed) price and the final nodal spot price in any period. In OTC markets, CfDs can cover any time period (from a few hours to multiple years), any node, with prices and quantities that vary over the year.
- **ASX baseload futures**: These products are effectively CfDs, but are standardised contracts of 0.1MW traded on the exchange, for either one (calendar) quarter or one month, and only trade at the Benmore node or Otahuhu node. The reference to "baseload" means that the same contract quantity (0.1MW) applies for every trading period over the month or quarter, i.e., there is no "shape" to them. These are the only contracts on the ASX which have market-making participants creating liquidity.
- **ASX peak futures**: These are CfDs, but settle only for periods in weekdays (excluding public holidays) and between the hours of 7am – 10pm. They are only available as quarterly contracts, and are available at both Benmore and Otahuhu nodes.
- **OTC "Super peak" contracts**: A more generalised version of a peak contract, only traded OTC[17] and apply only to the morning and evening "peak periods, e.g., 6am-9am, and 5pm-9pm, on weekdays. This is a better match to a residential load profile which, while elevated compared to night-time over the whole day, has clear morning and evening "peaks", especially in winter when heating and lighting loads coincide for a short period of hours either side of a working day.
- **ASX options**: The ASX lists options[18] on quarterly baseload futures at both Benmore and Otahuhu grid nodes, for a number of different strike prices. Additional options are listed with strikes 'near the money' if the underlying futures price fluctuates beyond existing strikes. Options are automatically exercised at expiry if they are in the money. Quarterly options expire at the end of the underlying quarter. Calendar strip options are also listed, which are an option on a 'basket' or 'strip' of 4 quarterly futures (making up a calendar year). These options expire in November prior to their underlying calendar strip (and therefore don't really cover hydro risk so basically have zero traded volume).
- **Swaptions**: Traded in the OTC market, these are "options on a swap[19]". These are CfD-like derivative arrangements which only come into effect if particular conditions occur. They

[16] Variation margins are a crucial difference between OTC and exchange-traded products. In the OTC market, "settlement" occurs only during the period for which the contract is purchased or sold for. For futures exchange products, settlement happens daily from the time the product is purchased until it expires, as the traded market price for the instrument varies. The cashflow implications for product holders are very different.

[17] Although note comments later in this paper which refers to the ASX currently consulting with its Australian electricity futures clients about whether a superpeak product may be preferable to the exist peak futures.

[18] An option gives the buyer the right, but not the obligation, to buy (call) or sell (put) the underlying ASX quarterly future to the seller of the option at a pre-determined 'strike' price. An option is said to be in the money if the underlying future price is greater than, for a call (or less than, for a put) the strike price. An option may only be exercised once. Typically the buyer of the option will exercise it if it is in the money at expiry. The payoff to the buyer would be the amount by which the option is in the money (ie futures price - strike price for calls). This payoff is asymmetric, and essentially insures the buyer against prices rising above the strike price (calls). In exchange for this, the buyer of an option pays a premium, which is the quoted price of the option.

[19] "Swap" is an alternative term for a CfD

are, in effect, more generalised versions of the ASX options described above, but covering various quantities, nodes, durations, and conditions which "trigger" the option (e.g., hydrology).

- **Financial Transmission Rights**: A range of products traded on the FTR platform which pay off based on the difference between prices at two nodes. There are a number of node "pairs" available to be traded.

In addition to products that are traded <u>between</u> parties, a market participant can manage its own wholesale risk through direct "physical" actions, e.g., investing in demand response or investing in generation or storage. Vertically integrated generator retailers are effectively internal risk management functions which reduce the need to procure risk management products from external markets/parties.

Risk management systems, models and policies

Risk management systems, models and policies represent the decision-making rules by which an organisation chooses which combination of products and physical actions it will take to manage risk. This is a range of combinations of:

i. Models that forecast what the organisation's physical exposure to wholesale market volatility will be at various points in the future, which is a combination of contracts already secured, expected customer numbers and consumption, and availability of physical options such as generation and demand response etc;
ii. Models which provide scenarios of future wholesale prices, as well as stress tests[20], which can be applied to the exposure calculated above to generate scenarios of financial outcomes; and
iii. Policies which determine what is an acceptable degree of exposure for the shareholders to take. These can be in the form of limits on financial exposure (e.g., Value-at-Risk and its variants, which measure the difference between expected value/gross margin and the 5th percentile margin from the scenarios described above) or limits on future physical exposure (e.g., hedges must be secured to cover 90% of monthly forecast consumption 12 months ahead, and 75% of consumption 24 months ahead).

Generally speaking, as time has passed, the ability to paint a richer view of risk through (i) – (iii) above has improved through increased data on inflows and prices (improving forecasting and scenario generation), as well as improvements in computing power and off-the-shelf software which enables better enumeration of exposure.

3.2 Information sources

Objective, quantitative evidence of adaptation in risk management is difficult to obtain without being able to directly observe the current and historical portfolios of market participants. There is data available on market-wide hedging volumes, which tells us about changes in the use of hedging instruments over time. This is useful, although is sometimes challenged by an inability to discern which products are being traded, and by what type of market participant. Hence the evidence presented below, while mostly accurate and objective, will only paint part of the picture of adaptation.

[20] Stress tests go beyond typical forecast price distributions and consider specific scenarios which involve a number of variables eg major generation outage, unexpectedly high customer consumption, and combined with downside pricing outcomes.

We consider five sources of information:

- The main source is the **Hedge Disclosure Database**, provided by the EA. This data allows categorisation by participant type, but does not distinguish between types of hedge products other than at a very high level of taxonomy. The other challenge with this source is data quality (errors in participant data entry) and difficulty with creating metrics such as "open interest" due to a lack of standardisation.
- **ASX hedging information** – this does not allow disaggregation by participant type but does separate hedge data into the specific products traded on the ASX.
- **FTR Registry data**
- **Stress Testing –** by design the stress test regime is highly anonymised and only summary statistics by quarter are available
- **Retailer growth, entry and exit data** – the EA's EMI provides high quality data here, although distilling the reasons behind retailer's exit required further research and relied on publicly available information

We present the analysis in two parts:

1. First, we ask if there is any evidence of a systemic inability or lack of desire of participants to hedge prudently. From the sources above, this would appear in an elevated number of participant exits or a worsening trend in stress test results.
2. Second, we ask if there are any discernible trends in the use of risk management products, which may suggest adaptation.

3.3 Is there any evidence of a manifest failure in participants' ability or desire to prudently manage risk?

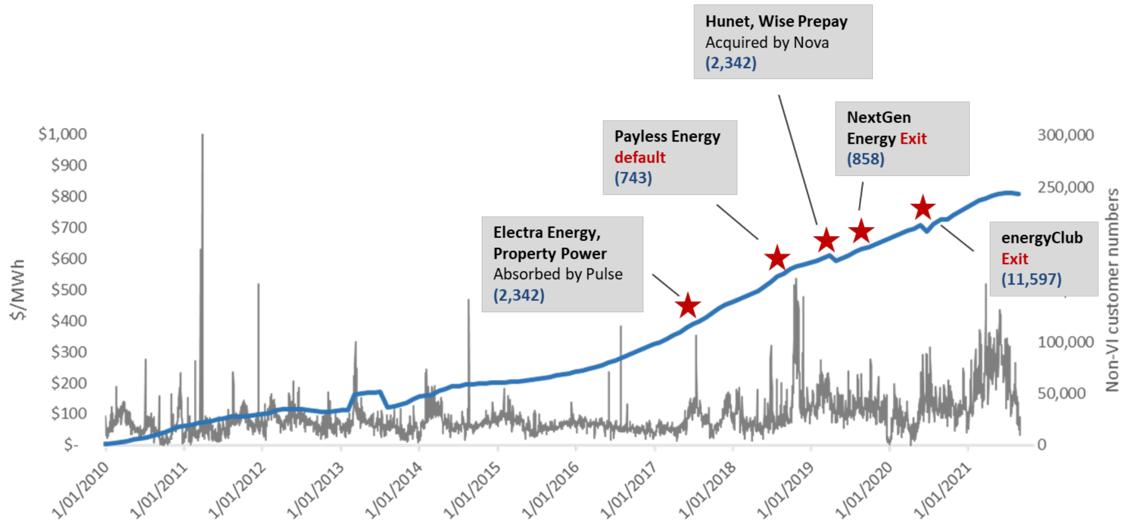
If there was a systemic failure to prudently risk management, a time of system stress would likely reveal an elevated level of market exits. We note that an exit *per se* is not evidence of a market problem or failure; as in many markets new entrants often have a heightened vulnerability to shocks when they are still establishing their businesses. Hence we might reasonably expect that in a rapidly growing market with a large number of new participants there is a spectrum of experiences, attitudes and policies around risk management; and the shorter the time a participant has been in the market, the less operating experience they presumably have. The electricity retail market certainly experienced rapid growth over the period 2010-2021, when the number of market participants registered as a retailer quadrupled from 10 to 40; the market share of independent retailers grow from 0.1% to 11%.

Some entry decisions may have been justified on optimistic customer growth assumptions (in order to achieve scale and experience) which weren't realised in time to deal with a period of wholesale volatility; the resulting exit was not related to <u>wholesale</u> risk management as such but unrealised ambitions or insufficient time to reach scale and minimum sophistication. Without significant research, it is difficult to provide a categorisation of exit activity, and we cannot conclude that every exit is evidence of a systematic problem with risk management.

Figure 1 presents the growth of independent retailers, and highlights the exit of any retailer who had, at any point in their history, more than 500 ICPs. The reason we focus on those with higher customer numbers is that we speculate they are more likely to have reached a level of scale where they have an understanding of wholesale risk, hence their exit decisions are less likely to be a result of imprudence or inexperience[21].

We note there were another 7 retailers who exited over the period 2018-2021 who had lower customer numbers, leading to a total of 13 exits.

Figure 1 – Average daily wholesale prices, non-vertically integrated customer numbers and major retailer exits. Source: EMI.



In our over-500 category, there have only been three exits that have been publicly reported as resulting from wholesale market stress[22] - Payless Energy, NextGen Energy and energyClub. It is possible that the other exits that resulted from acquisition (four retailers in the chart above) were also experiencing wholesale market stress which hastened acquisition discussions, however, that is not apparent from information we have reviewed.

The Authority's stress testing regime provides another source of potential evidence regarding changes in risk management. One might expect that changes (improvements or deterioration) in approaches to risk management would be reflected in changes in performance against the various tests[23] applied by the Authority.

The scenarios that participants must apply to their portfolios correspond to an "energy" (dry year) event and a "capacity" (short-term peak) event. Figure 2 and Figure 3 show the full history of stress testing data for the "cashflow"[24] test, by quarter, for the energy scenario and capacity scenario respectively.

[21] Out of the 14 retailer exits that occurred in the period 2017-2021, 10 had been registered market participants for 3 years or less.
[22] As reported in EnergyNews
[23] More information on the tests required by the regime, and the scenarios applied, can be found here: https://www.ea.govt.nz/operations/wholesale/spot-pricing/stress-tests/ . The two scenarios required are: (i) an "energy" stress test being a prolonged (one quarter) of wholesale prices averaging $400/MWh, and (ii) a "capacity" stress test for spot prices being $10,000/MWh across 8 peak hours of one day, at a time in each quarter determined by the Authority (as being the peak NZ demand in that quarter).
[24] The cash flow measure is a ratio of the change in cash flow due to the nominated stress test over the last reported value for annual cash flow (EMI)

Figure 2 – 25th percentile and 75th percentile reported results under the "cashflow" test for energy stress test[25]

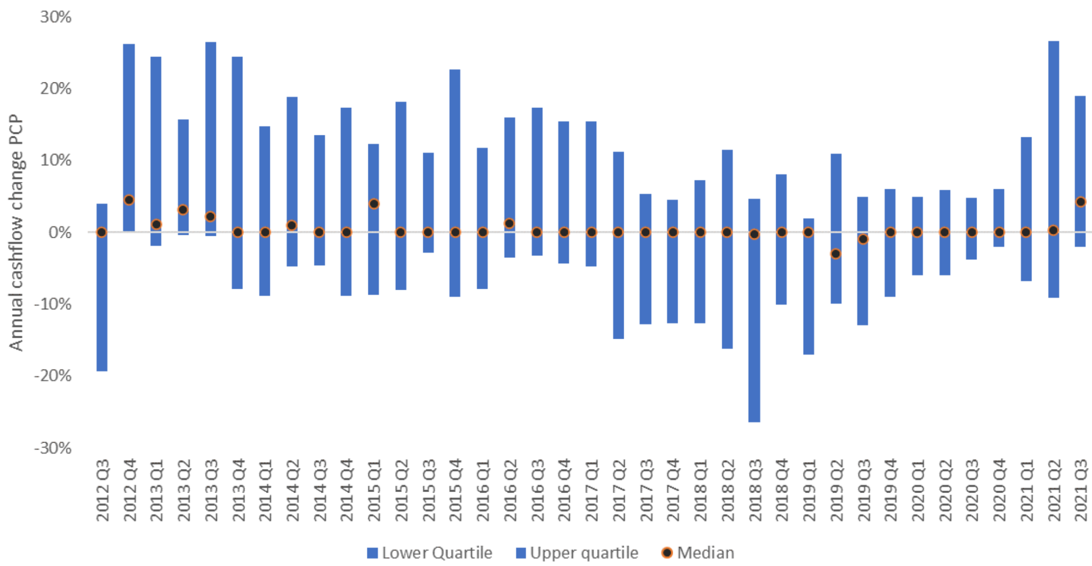
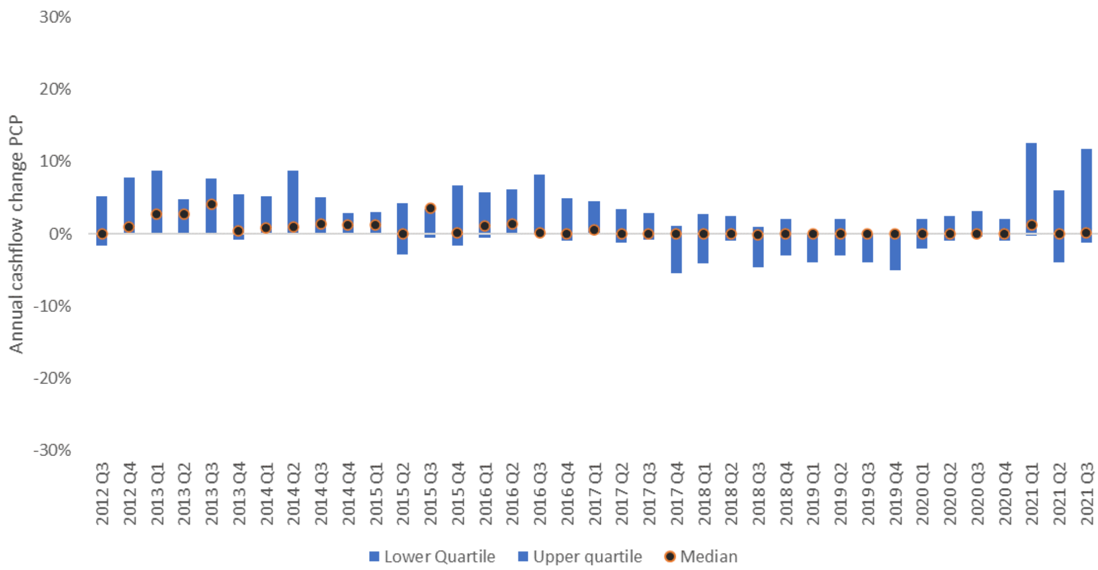


Figure 3 - 25th percentile and 75th percentile reported results under the "cashflow" test for capacity stress test



These figures illustrate some interesting trends. Firstly, we observe that the results of the stress tests[26] have changed through time. Data for the period 2012-2016 suggests the tendency is for portfolios to *improve* under the stressed scenarios (which suggests long portfolios, potentially through over-hedging or the use of flexible generation). In 2017-2019, though, we observe a tendency for the scenarios to worsen cashflow; and following that, a recovery back to positive results in stress scenarios. We can only surmise that either:

[25] The EA data only reports the maximum, minimum, median and 25th and 75th percentiles. We have chosen not to show the maximum and minimum, as they typically sit at +100$ and -100% for both metrics and obscure the patterns in the distribution. The addition of, for example, 10th and 90th percentiles would be insightful.
[26] To be correct, the middle 50% of the distribution shown in these charts. .

- hedging policies may have relaxed during the latter part of the benign wholesale price period of 2014-2016, and then responded to the volatile 2018-2019 period by tightening up again, and/or
- the stress test results started to include test results from new retailers[27] in the 2018-2019 period who were less well hedged, pulling the distribution down.
- The improvement in the later period reflected the exit of less-hedged retailers from the market (and thus from the stress test results).

We also note that two changes to the Authority's stress test scenarios may explain some of the variation in the data. The regime was unchanged from its first publication in 2012 until 15 November 2019. It then included a temporary, additional capacity-based stress test to apply for the first quarter of 2020. The regime was reviewed again in 21 January 2021 to update the energy shortage scenario from an average spot price of $250/MWh to $400/MWh, which may explain the "widening" in the last three bars in Figure 2(a).

Without more granularity of data, it is difficult to determine which of these effects dominates.

We can also see that the energy and capacity tests behave in approximately a similar manner through time, which we hypothesise reflects the fact that both risks are being managed using similar products (presumably baseload), rather than products tailored to each type of risk event (as might be the case if e.g., cap products were widely used).

In summary, without further information, we do not believe that the above retailer exit data and overall stress test results (which may show a degree of adaptation) provides sufficient evidence that there is a systemic problem with prudent risk management or failure of market participants as a whole, or as a cohort, to adapt to changing market conditions.

3.4 Are there any discernible trends in the use of hedge market products, which may evidence adaptation?

Below we present hedging volumes over the past decade. Where possible, we consider the different hedging behaviour of each cohort interviewed in Section 4, and for this we primarily rely on hedge disclosure information, as outlined in Section 3.2.

The manner in which the hedge disclosure data was accessed presented a number of data challenges. Some of these challenges related to data quality, namely inconsistency, errors and gaps in the way market participants entered data. The way hedge volumes were recorded, along with a lack of product definition prevented an accurate portrayal of "open interest" [28]. Hence the information presented below shows total volumes traded by month, noting that this will not correctly reflect open interest because of:

i. No information about whether the contract is baseload over the period, or seasonally/monthly shaped

[27] The number of participants providing stress tests, while not systematically reported by the Authority, increased from around 23 prior to 2016, up to 29 for the 2016-2019, then ~34 from 2020. What effect this had on the results is not possible to disaggregate from the data available.

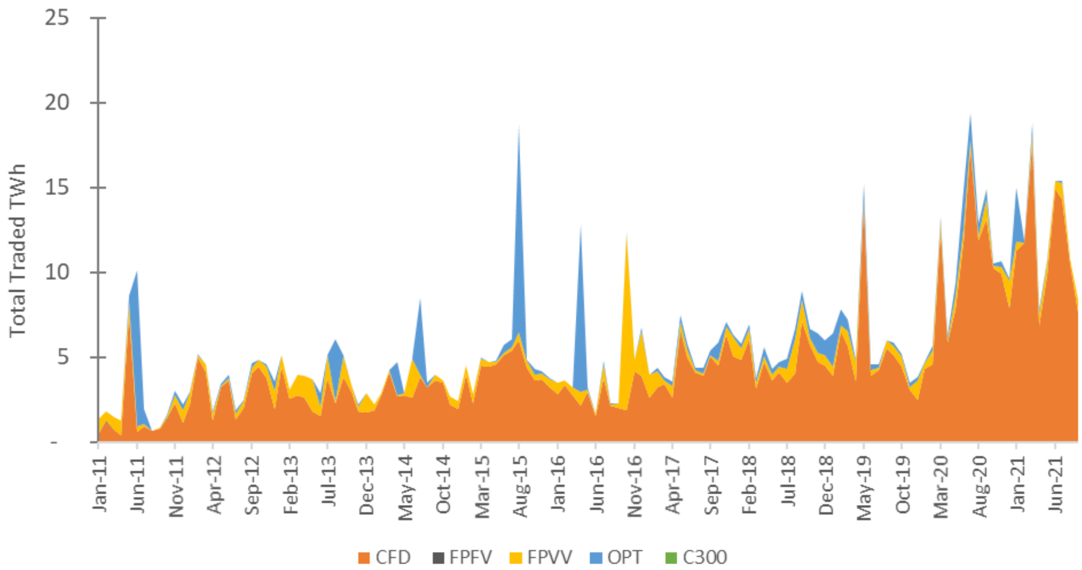
[28] Open interest is a measure of the volume of energy in contracts held by market participants at each point in time that have not expired, been exercised or offset by an opposing position. It is, in essence, a measure of the market's aggregate exposure.

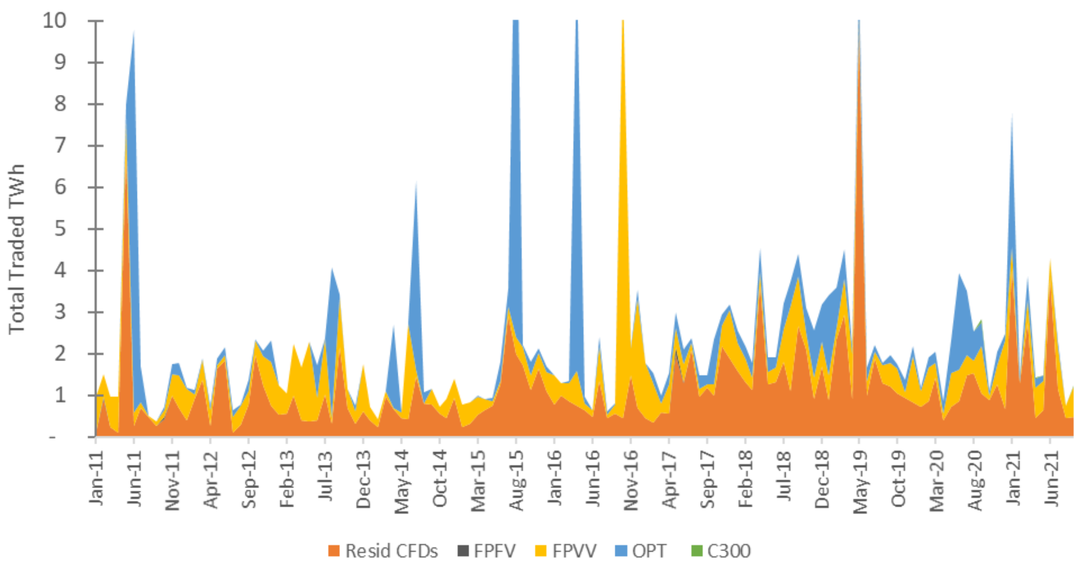
ii. Some ASX trades would have closed out a previous position, thus reduced open interest, but were counted as an additional trade.

More advanced analysis of the data could rectify (ii) above; however (i) would not be possible with the limited information about each product that was requested of the submitters.

Figure 4 below shows total hedge market volumes by month, broken down by broad product type. CFDs dominate the market, noting that this is a broad category including shaped CfDs and any exchange traded baseload and peak futures. In fact, Gentailer trades on the ASX make up, in aggregate, around 80% of the orange shaded area in the chart below (recalling that the chart shows the total volume of trades in a month, rather than open interest). The second chart below removes gentailer trades with the ASX.

Figure 4 (a) and (b). (a) shows total market traded volumes for each month; (b) removes gentailer ASX trades in baseload futures, presuming that the vast majority are market-making related.



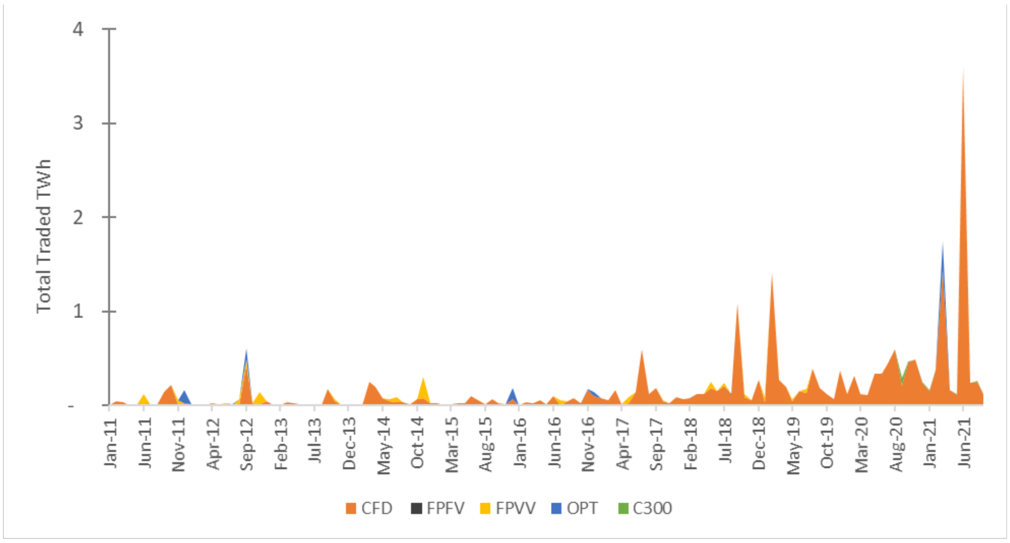


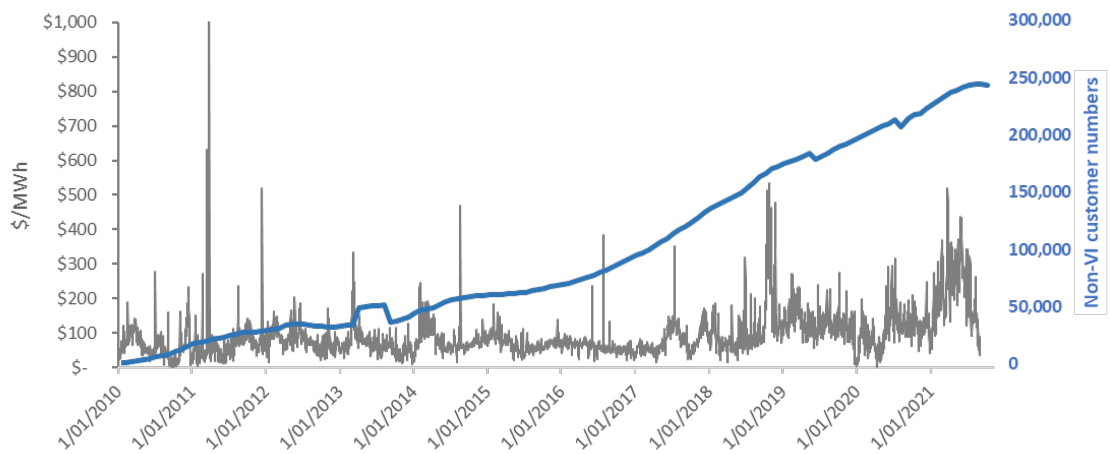
The two charts show firstly the dominance of gentailer market making on total CfD volumes traded. The second chart, which removes ASX market making trades by gentailers, illustrates a modest increase in residual non-market making related trades, mainly in CfDs, over the decade, and most pronounced during the recent volatile period – hedge trading appears to have increased in response to volatility. Again, an open interest view of this data may illuminate more.

Independent Retailers

Figure 5 below shows hedge volumes for independent retailers. Here there is a clear trend of increased hedging (almost exclusively CfDs) as the number of retailers and their customers increased. Separating the hedging drivers of increased volatility in 2018 from increasing customer numbers is difficult, although the increase in hedging seems to align with the acceleration in non-VI customer growth observed after 2015, and prior to the volatile period.

Figure 5 – (i) Independent Retailer hedge trading volumes by month, and (ii) daily average wholesale prices and non-VI retailer participant customer numbers.





Gentailers and Industrials

Gentailer and industrial hedge volumes are shown below in Figure 6 and Figure 7. Gentailers' recent increase in ASX market making in is shown clearly, with a commensurate decrease in the proportion that options and FPVV contracts now make up of their trading activity. It is also clear that gentailers have been the primary traders of option contracts.

Figure 6 – monthly gentailer hedge volumes traded by product category

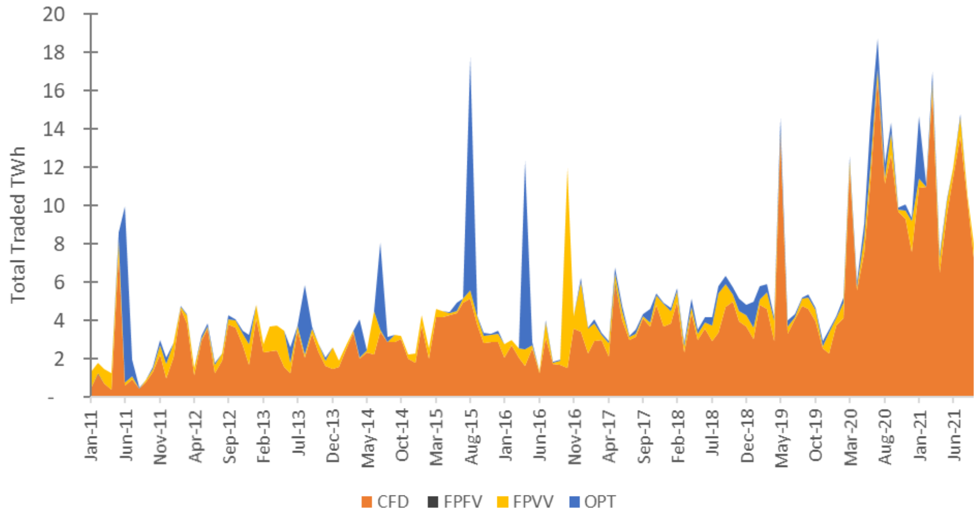
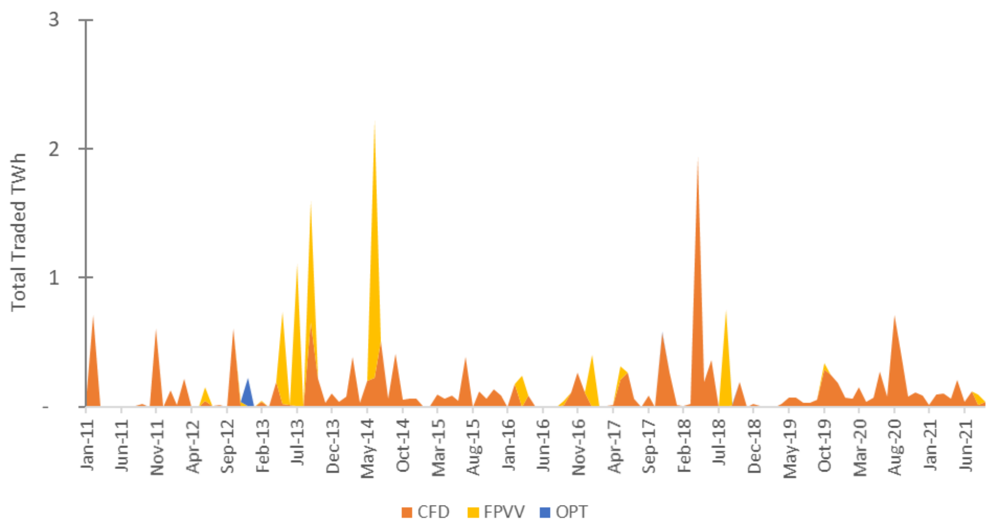


Figure 7 - Monthly industrial hedge volumes traded by product category

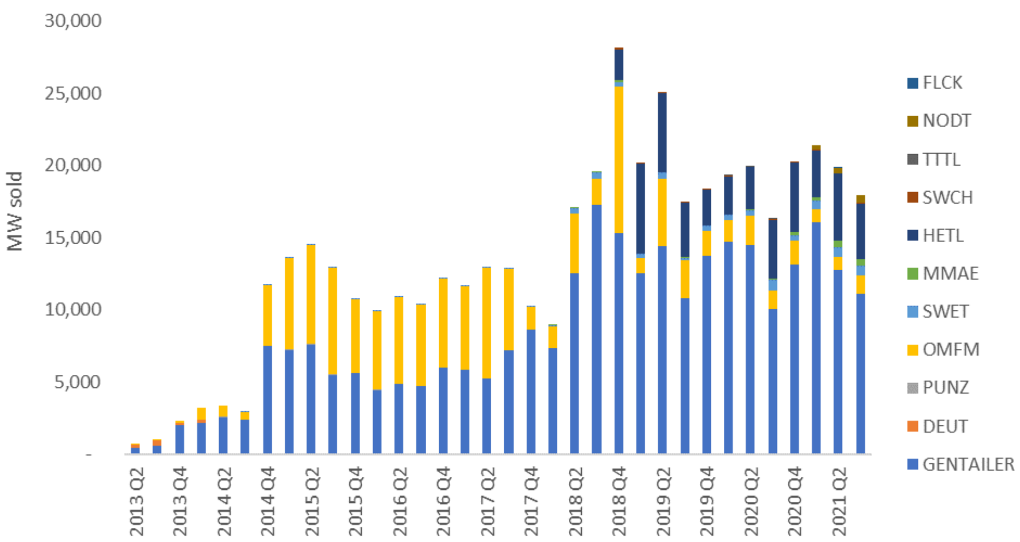


Other than a gradual move away from FPVV contracts to CfDs, it is difficult to discern any trend in industrial contracting[29].

Finally, Figure 8 shows that the number of participants actively engaged in the FTR market has increased since the market commenced in 2013. While gentailers still dominate volumes traded, the number of non-gentailer traders has increased from 2 in 2017 to 6 in the third quarter of 2021. That said, the non-gentailer volumes are dominated by trading organisations (Haast and OMF).

Figure 8 - FTR total volumes traded by quarter, by participant

[29] These volumes don't include the majority of the contractual arrangements between Meridian and NZ Aluminium Smelters



4 Surveys of Market Participants

A group of 12 market participants, spanning vertically integrated generator-retailers ("gentailers"), industrials, independent retailers and brokers/traders were interviewed. A standard set of questions was asked, spanning

- their historical and current experience and practice of wholesale market risk management,
- current perceived impediments to risk management, and
- their expectations of how they, and the wider market, will be able to adapt to a future that is likely more volatile as the market transition towards 100% renewables.

Care was taken to ensure "risk management" was explored both in the context of access to risk management products (principally hedge contracts, but also demand side response, storage and generation investment) as well as their modelling, policies and decision making around risk exposure through time.

A summary of the themes emerging from three "cohorts" (Independent retailers, industrials and gentailers) is presented below. Comments from broker/traders primarily related to independent retailers, but included commentary on the other two cohorts as well, hence these insights were provided in the sections relevant to each.

This survey was conducted in October 2021; there is always a risk that a relatively small survey is dominated by perceptions, issues and frustrations that may be relevant to the time but perhaps transitional[30]. There are few ways (other than repeating the same survey at regular intervals[31]) to adjust for this, but the insights gained do need to be considered in this light.

[30] An advisor to the survey design and interpretation commented that, had the survey been conducted in April of the same year, some of the answers would have been different.

[31] The Authority has, in the past, undertake a biannual Hedge Market Survey through market research firm UMR. The last one we are aware of was in 2017. The results of these surveys are weighty documents, and probably don't provide the insights we are attempting to capture here. Changes to this survey to make the questions more succinct and quantifiable may be a useful way forward.

We also note that, given the number of independent retailers currently in the market, care should be taken in extrapolating the insights from the three[32] interviewed, to the whole independent retail market of ~30.

4.1 Independent Retailers

4.1.1 Has their risk management improved over the past 10 years?

All retailers spoken to unequivocally stated that their own risk management had improved over the past 5-10 years. The improvements arose across:

- the way in which they used hedge products[33],
- their understanding of risk[34], and the way they modelled it, and
- the way they translated their understanding of risk into decisions regarding exposure and hedging.

All retailers spoken to cited the key role of coal and gas in the recent market dynamics, and some retailers had adapted by investing heavily in advice and modelling regarding the outlook for fossil fuels.

Sophistication and Horizon: That said, within the cohort of retailers, the current degree of sophistication varied. There was a mix of physical position limits (usually expressed as a % of purchases, declining through time) and financial measures (e.g., VaR, CvaR etc) being used to measure exposure, with a bias towards physical limits, generally because they were computationally easier to calculate. Most retailers used a 3 year timeframe for hedging (with most of the focus being on 12-18 months), to align with ASX pricing.

Notwithstanding that, a broker commented that the sheer uncertainty in the current volatile market is, somewhat counterintuitively, leading independent retailers to shorten their hedging horizon. Reasons included uncertainty in customer growth (compared to “hockey stick” assumptions of a few years back) and uncertainty in pricing more than a few quarters into the future. However, we have not been able to find evidence for this in the hedge disclosure data. Figure 9 shows the average number of days in advance of a contract commencing that a trade takes place, and the average term of a contract, for independent retailers. It shows that while the contract term has decreased (as quarterly ASX contracts dominate), the average lead time for contracting has stayed relatively stable at ~14 months since 2016.

Figure 9 – average hedging horizon (number of days in advance a contract is traded) and average term of contract for independent retailers.

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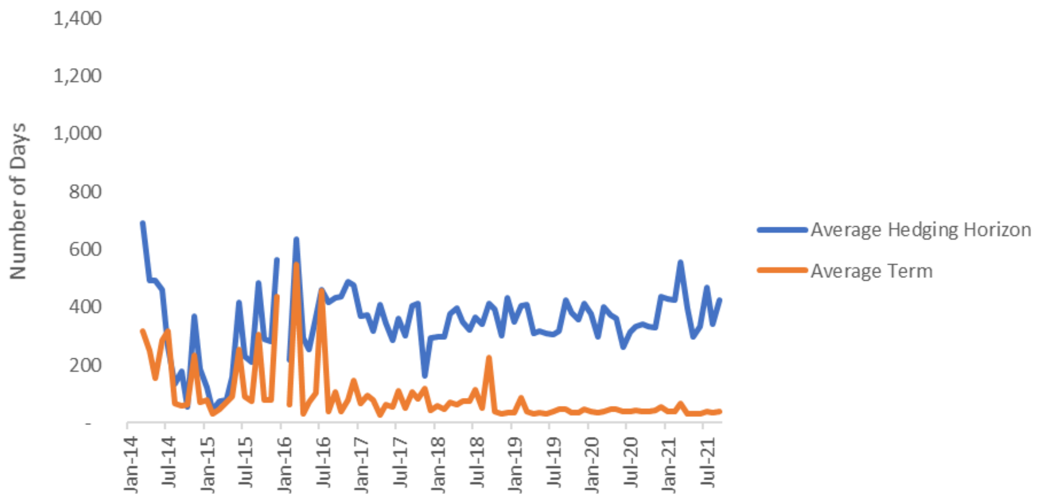
[32] That said, the three broker/traders spoken to also commented at length on their experience in providing risk management services to independent retailers.

[33] One retailer stated that in 2010, a retailer either had to have “deep pockets or a really good FPVV”; now, even with primarily baseload products available, there were more options available

[34] One trader/intermediary suggested that retailers they had worked with were too focused on using the forward market to hedge spot market outcomes, and did not understand or focus on forward market risk. A more volatile spot world could lead to a more volatile forward market, with serious cashflow implications for parties using exchange-traded futures.



Baseload hedges were the main hedge product used by the retailers spoken to. When sufficient liquidity existed, peak-related products were the next most commonly used. Straying much beyond that was limited to one or two participants who had priced, and sometimes transacted on, caps, FTRs or ASX options.

Demand Response: Most (but not all) retailers spoken to had considered demand response as a risk management mechanism, but actual use of demand response was limited to a small number. A number found the current environment (e.g., hot water control in the hands of network companies, low penetration of EVs) made the costs outweigh the benefits. One cited the importance of aggregators to higher liquidity and efficiency in demand side flexibility products.

4.1.2 Do they perceive impediments to better managing risk in the current market?

Current difficulties with achieving better risk management cited by the retailers spoken to included:

- The recently declining liquidity in peak-related products (exchange-traded and OTC), which is reducing their ability to better match the profile of their exposure. One retailer believed a sufficient *range* of products existed today, and liquidity in those products was the main issue. Another stated that there had been a reduction in the number of (peak or profile related) hedge products being priced in the OTC market, compared to 2-3 years ago, specifically calling out cap products, which were now less frequently priced by some gentailers compared with a few years back[35]. That said, they noted that, even when they were priced historically, their perception of those prices was that they were too high;
- ASX initial margin requirements had increased significantly over the past few years (3-4 fold[36]), and the cashflow implications of variation margins was onerous for small retailers. The initial margins required for the ASX added to the prudential burden borne by purchasers in the spot market, but due to the two markets existing in separate jurisdictions, previous efforts to offset domestic prudentials with ASX margins had not been successful. Most retailers spoken to tried to use ASX sparingly for these reasons reason;
- Simultaneously, significant tightening of credit conditions required by gentailers in the OTC market over the past 3-4 years was making it difficult for some to access the OTC market

[35] A peer reviewer of this paper also perceived that scale mattered to pricing, especially in more sophisticated instruments like caps. Requests by small retailers for low-volume caps seemed to attract pricing that included the full transaction cost from the seller's end.

[36] See discussion in Section 6.1.3 about the underlying reasons behind this.

which is where both standard CfDs and more tailored products (node, term, shape etc) can be priced;

- Shorter expiry periods for pricing (one cited that 2 week expiry was the norm in 2017, whereas now 24 hours was more common);
- Retailers are being cautious about entering the increasingly active PPA market. While PPAs may have attractive pricing, they resulted in 5-10 year commitments that extended into a period where market pricing and volatility was highly uncertain (due to factors such as Huntly, Tiwai, TCC closures, ongoing gas issues etc), as well as their own growth. One retailer cited the challenge with renewable PPAs (especially wind) being the inability to match with the typical retail profile in the short term[37].
- One retailer cited the confluence of uncertainty, credit-related challenging access to OTC products and the duration of the (market-made component of the) ASX curve meant that it was difficult to respond to a market move from 2-3 year C&I retail contracts towards 5-years[38].

4.1.3 Will their risk management continue to improve in the future?

All retailers were alive to the likely increase in market volatility as the market continued to move towards 100% renewables. Some foresaw a shift from the market being dry-year constrained to capacity constrained, while there was general agreement that the near-term transition issues (thermal decommissioning driving short-term volatility and in turn increasing the need for greater liquidity in profile-related contracts) were more pressing than addressing the question of market dynamics once 100% was reached. All mentioned the closure of Huntly and Tiwai, the changing role of gas, and the significant uncertainty this introduced into forming expectations of price, and price volatility. Generally, there was greater concern about short-term peak/capacity related price volatility than there was dry-year risk.

All were adamant that their risk management policies, tools and frameworks would improve in the future – examples included better modelling of price distributions, and moving from position limits to VaR-type measures. One retailer cited a near-term aspiration to move into trading FTRs.

Notwithstanding that, all independent retailers expressed the view that the biggest barrier to improving risk management was some combination of poor liquidity in existing (profile-related) hedge products and low expectations of hedge product innovation. Some were adamant that requiring market making in existing ASX peak and option products was a necessary approach, while others suggested the nature of “shape” and exposure risk may be best dealt with through the OTC

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[37] One retailer spoken to raised this issue regarding their consideration of a solar PPA. Another party cited the challenge with intermittent generation PPAs being experienced in Australia, not well understood by corporate customers, that the VWAP discount is significant due to a prevalence of wind and/or solar depressing non-peak prices, and the absence of solar/wind elevating peak prices. As a result, customers were surprised to see overall (load-weighted) electricity procurement costs increase following the signing of a PPA with an underlying energy price that was lower than a retail tariff.

[38] Which we understand is driven by a desire to give C&I customers more certainty of price.

market rather than the ASX peak product[39]. This included encouraging more liquidity in caps[40], or peak-related products better suited to retail profiles such as EnergyLink's "flex CFD", "superpeak"[41], or 7-day peak product, all of which are most likely to be traded in an OTC environment.

[39] As outlined earlier, the ASX peak product is a quarterly product where peak periods are defined as weekdays, 7am – 10pm. Depending on the mix of customers, the effectiveness of this hedge across a 3 month period, or between summer and winter, can be highly variable. This highlights the issue with the high degree of specification required for exchange-traded products. Further, as noted above, the cashflow cost of trading in the ASX is a deterrent to smaller retailers, especially as a result of daily settlement where the timing of settlement payments does not coincide with the time period where the contract is needed.
[40] Noting that one retailer suggested these could be traded on an exchange or platform similar to the FTR market.
[41] Shortened hours of peak periods e.g., 6am-9am, 5pm-9pm

4.2 Industrial/Large Commercial

4.2.1 Has their risk management improved over the past 10 years?

Respondents confirmed that their overall risk management had improved over the past 10 years. One had made a significant shift from relying purely on FPVV retail contracts to a mix of spot exposure, ASX (primarily) and OTC products (as can be seen generally in Figure 7 above).

The significance of this evolution cannot be overstated given the challenges faced by the energy procurement groups (sometimes just individuals) inside the industrial participants. Industrial consumers primarily trade in (international) markets for their final product, which is largely unrelated to electricity markets. One party cited the difficulties associated with obtaining sufficient comfort at senior executive and Board level for using more sophisticated products than baseload hedges. One party had toyed with quarterly futures options a few years ago, but believe the variable appetite for options depended as much on the trader at the time than anything else. While one party is considering adding modest PPAs to the book (as part of an evolution of approach), the non-firm nature of intermittent renewable PPAs against a largely baseload purchase profile was a challenge to sell internally, from a risk management perspective – despite apparently attractive prices.

Participants spoken to used position limits (e.g., as a percentage of quarterly volume) to guide exposure. These limits decline through time usually over periods of around 3 years (where ASX products or indexing/marking-to-market is available), although the profile of decline was quite different between the two parties spoken to. One cited that their exposure limits through time is quite permissive to allow value tradeoffs if hedge prices aren't attractive.

Both parties saw the risk management role of demand response for their organisations as very limited – mainly because of the inflexibility of the industrial process and the need to move product to market. Reinforcing this was the view that a tendency to be highly hedged or overhedged dampened any incentive to employ more flexibility in demand, despite the incentives in a CfD structure. That said, various observations were made about the ability for cogeneration to be flexed to manage short-term exposure in some industrial settings, both for them and other major users.

4.2.2 Do they perceive impediments to better managing risk in the current market?

One party spoke at length about lack of transparency in market pricing – including:

- current spot prices (relative to storage),
- the opaqueness of water values,
- the level of the current forward curve, and
- the gaps in pricing between ASX, CfDs and PPAs.

They were always able to get prices from the main market players for the OTC products they sought, but the pricing was not easy to reconcile with their own internal forecast spot prices. This was exacerbated for pricing beyond the 3 year ASX product term. Thus their appetite to pay was low as a result, and hence they preferred exchange-traded products. This, combined with a perceived opaqueness relating to recent spot market levels and volatility, led to a lack of trust in the market – at a time when industrial users are in a challenging environment – which, amongst other things, limited their ability to use a wider variety of products.

One party mentioned the challenge of not being able to do hedge accounting on PPAs, if there is any degree of variability in them. This requires the party to carry the movement in market value of the PPA on their P&L, which is potentially a hurdle to participating in the market for intermittent PPAs.

4.2.3 Will their risk management continue to improve in the future?

One party noted the apparent immaturity of risk management relative to other market participants, but that further improvements would be challenged by the degree of focus that their Board would likely put on electricity risk management.

Another expressed a desire to continue to evolve and see improvements in the way that their electricity portfolio is managed, acknowledging that they have not yet achieved the optimal mix of physical (cogeneration, PPAs) and financial risk management products. They cited two different future pricing scenarios posited – one indexed to the (PPI adjusted) LRMC of new renewable generation, the other reflective of a highly volatile zero-SRMC world – that presents internal challenges to embracing long-term PPAs in any significant way, and so are pursuing a gradual approach here.

4.3 Generator-retailers (Gentailers)

4.3.1 Has their risk management improved over the past 10 years?

Gentailers were, generally speaking, positive in response to the question of whether their risk management had improved over the past 10 years. They agreed that risk modelling had improved, over the past decade – often as a result of improved computational power, the evolution of digital and coding capability within the organisations, and simply the availability of more market and inflow data as time passed. In respect of having improved their optimisation of hedge products, all commented that they were more actively trading, and across a wider range of timeframes and products than 10 years ago, albeit to differing degrees. Most expressed confidence that the market overall (including rule changes) was evolving and adapting well.

The timeframes over which their risk management and portfolio optimisation focused was highly context specific, related mostly to the underlying fuel and plant (e.g., refurbishment cycles) in their generation fleet. More advanced (financial) measures of exposure (such as VaR) were commonly used, multi-faceted across fuels, storage and market expectations.

A number of parties stated that the ASX was the biggest change over the past 10 years, providing a powerful tool for managing risk and price signalling, and that the volumes they traded through the market had increased significantly. One referenced the attraction of ASX trading was principally anonymity and the ability to "chip away" at a large volume rather than have to directly enquire of a market participant for the full volume on a large bilateral/OTC contract; also that it is an extremely good credit management system.

Generally there was a view across gentailers that the current hedge product suite was adequate, and that further innovation would be driven by the demand for new products; there were low barriers to innovation in the OTC market.

A range of comments were made about product liquidity and development:

- One commented that product innovation over the past 10 years beyond baseload products was perhaps limited by the need being largely driven by the energy balance (security of supply), rather than capacity issues, and that this was largely dealt with via baseload contracts, with some optionality around dry years (e.g., swaptions). However, most experiences of product innovation were very positive, allowing participants to trade different nodes[42], different timings, profiles (superpeaks), WD/OD, time swaps, swaptions with different knock-ins/outs, ancillary service hedges etc as it was not tied down to a product specification on an exchange.
- The swaption was evidence of the market's ability to fit products to the nature of security risks, although one party observed that buyers' valuation of swaptions was not homogeneous and was linked to the degree of dry-year risk exposure
- In respect of caps, a number of gentailers stated they hadn't been asked for cap pricing in a number of years, or that requests were very infrequent; hence they wondered how significant the demand for caps was.
- Some acknowledged that changes to their generation portfolio had implications for their own risk management, but differed in terms of the degree this had impacted their ability to provide the market with liquidity in (especially shaped) products: One reinforced they had a long-standing policy of pricing every OTC request made to them, and the generation

[42] One suggested that historical product innovation driven by e.g., transmission constraints had now been reduced through transmission upgrades and the evolution of the FTR market.

portfolio changes simply required them to adapt in the way they used other portfolio tools to continue this. They specifically referenced the ASX market as being critical to this.

There were varying degrees of investigation into demand response as a tool – it is known publicly that two major gentailers are looking at a large demand response scheme in the form of a hydrogen production facility, and beyond this there are a range of initiatives and investigations underway, with some gentailers declaring publicly the strength of their intention to secure large volumes of demand response.

4.3.2 Do they perceive impediments to better managing risk in the current market?

The significance of the cash cost of trading on the ASX was emphasised, citing (as had some independent retailers) the increase in initial margins over the past few years. In this context, some parties expressed support of the Authority's move to commercialising market-making contracts as this should make explicit the cost of providing that service.

A number stated the view that the OTC market had been, and should continue to be, where product *innovation* occurs; a regulated product – especially ones that attempted to deal to profile risk - risked being too homogenised in a market where the nature of any individual retailers profile could vary markedly across the industry. Products could be tailored to an individual need in the OTC market.

While a vibrant PPA market is emerging, which some of the gentailers spoken to were actively participating in, credit was acknowledged as an issue: the potential counterparties for PPA sellers were probably limited to those where the seller could be confident they would be around in 10-15 years, particularly given where the likely price of the PPA versus actual prices at the time might be (and the impact of this on independent retailer competitiveness)[43]. This likely restricted access for independent retailers and C&I customers.

4.3.3 Will their risk management continue to improve in the future?

Parties had a range of views about the relativities of short-term capacity risk, hydro firming, or dry year risk through, and beyond, the transition to 100% renewables. That said, the dominant view was that dry-year risk was going to be the most difficult to solve in a no-thermal future. In addition:

- In terms of investment options to support risk management as we move towards a 100% renewables market, most parties stressed the importance of managing gas and coal availability, and the thermal generation assets, over the next 10 years[44] to provide dry year risk management and fast-start plant. Solutions varied from the generic need for a clear agreed plan for the gradual retirement of thermal assets; the ThermalCo proposal as a (preferably) market-driven evolution that would stabilise the role of thermal plant in providing short term, medium term and dry-year capacity and risk management products to the market in a standalone entity; through to market-driven decommissioning, noting that this was expressed in the context of a scenario where some thermal was retained purely to

[43] A broker spoken to, who works extensively in the PPA market, did note that many of the 10-15 year PPAs had 5 year price reset clauses based on either expert analysis or ASX prices, and/or ASX-referenced prices (e.g., within upper and lower bounds) after that time. This effectively rebalances the risk back towards the investor, but not until after 5 years of up-front cashflows at ~LRMC.

[44] Some parties maintained that, beyond the transition, continued access to reliable, flexible but infrequently used fossil fuels (either coal stockpile or gas storage) was preferable to the investments contemplated by the NZ Battery project to solving the dry year problem, at least while more practical and scalable renewable options e.g., biomass are worked out.

solve dry year problems, i.e., that it would run very infrequently, and potentially with a renewable fuel (E.g., Huntly re-fitted to run on biomass). Some expressed nervousness about leaving it to current owners (individually) to determine the decommissioning timings in their own portfolio's interest

- One party suggested the priority for the industry is to determine how to share the burden of physical risk management (i.e., the plant required to underpin dry years), rather than leaving it in the hands of one or two market participants.
- Views on grid-scale batteries to eventually (as costs come down) solve short term volatility were generally positive.
- Demand response was seen as an important component of a 100% renewables market, but a number of participants still felt the emergence of material DR was not straightforward. For example, two noted that the prospects for medium term demand response (weeks-months) was critically dependent on industries where supply chains are linked to locations elsewhere internationally, and thus could allow reallocation of production to support demand reduction in NZ.

Together, batteries, biomass, demand response and hydro storage were seen as vital to providing the price discovery role that thermal assets currently provide.

Some gentailers believed that caps (for example) were likely to play a bigger role in the market as volatility grows with the transition to higher renewables, but expressed caution about listing additional products on the ASX without a really strong evidence base for the demand – as outlined above, standardising and exchange listing a product was putting in place an expensive gold-plated solution. In addition, requiring market making for products with low demand results in additional cost[45]. Some emphasised they would be supportive of listing cap products on the exchange, if the demand could be evidenced, but were more circumspect on their support for market making requirements. As discussed above, some saw the OTC market, rather than the ASX, as being best suited for product innovation for the future.

In respect of the PPAs, there were two major issues raised.

- In respect of the credit issue raised above, some participants mused on whether there was a role for an intermediary to provider PPA insurance[46]. Reference was made to the fact there is significant experience in PPA markets overseas and some insight as to how to manage these issues could be gleaned from that; noting the caveat that the international market may see a much bigger cohort of highly creditworthy counterparties (e.g., Apple, Amazon, Google) than might be observed currently in NZ.
- Concerns were also expressed about how the firming of intermittent PPAs would be coordinated and priced e.g., whether the assumption of developers was that large generators would be the primary buyers of PPAs and thus provide firming from within their existing portfolios, or would developers be able to widen the buying pool by making PPAs more attractive to industrial/retail buyers through augmentation with a firming derivative. Ultimately, the concern was whether developers understand or accept that intermittency has an associated risk (and thus cost) from a purchaser's perspective, and this cost was ultimately going to be borne by the developer through a purchase of a firming derivative (if

[45] And, as outlined later, come with potentially significant initial margins.
[46] A similar suggestion was made by an industrial participant regarding a PPA registry/insurance scheme, potentially using the EMS tradepoint platform.

available) or through discounts applied by potential purchasers, once the effect became sufficiently material[47].

5 Regulatory and political influence on risk management

One theme raised through MDAG's discussions with stakeholders was that the lack of political or regulatory palatability of high prices had a supressing effect on the revenue adequacy of firming plant. The inference was that these factors prevent the price duration curve (PDC) achieving the shape and level required to support the optimal combination of resources (demand response, storage and generation).

This relates to risk management through two factors:

- the willingness of purchasers to pay for the hedge contracts which insure holders against high prices; typically underwritten by owners of firming/peaking plant
- the ability of owners of peaking/firming plant to manage utilisation and thus revenue risk through the contracts market

Potentially, one driver of the perceived lack of demand for caps highlighted through the surveys could be that the peak end of the PDC was being supressed, and therefore a gap emerged between the willingness to pay for cap products, and the seller's belief in the true value of the insurance.

An energy only spot market is founded on an assumption of uncapped price discovery reflecting the value of energy at every point in time[48]. We consider here whether there is any evidence of politically-motivated spot price suppression, drawing on both quantitative evidence and insights from the surveys.

5.1 Historical interventions in the wholesale market

The most overt political or regulatory interventions in the spot market occurred in the decade prior to 2010. These exclusively relate to the management of dry years and include the combination of public conservation campaigns (called by the Minister of Energy in 2001 and 2003) to reduce demand, and by the actions of the Electricity Commission in terms of altering the offer price of the reserve energy plant Whirinaki during the 2008 dry year[49][50].

We also note that decisions by the Electricity Authority (and the former Electricity Commission) to alter final prices as part of an Undesirable Trading Situation (UTS) decision are regulatory interventions, noting that these actions are taken to address market behaviour which meets the requirements for a UTS, and are subject to extensive consultation and a high level of scrutiny. Since

[47] See footnote 37

[48] In the short-run, this particularly includes the opportunity cost of the fuel (which includes water) and the scarcity value of the electricity produced, with the discovery of the clearing price disciplined by effective competition. Put another way, the clearing price should reflect the cost of meeting the next unit of demand from the lowest cost source, whether generation or demand reduction.

[49] No official conservation was run in 2008 – the Electricity Commission had negotiated large-scale demand reduction agreements with industrial users but rainfall ended the need before these had been executed

[50] Although we note that the Electricity Commission at the time "*strongly denied….that it sought to influence market prices, and states it was motivated only by concerns about the balance between thermal and hydro generation.*" Irrespective, its actions had a material effect on dispatch and prices during this event. For a comprehensive assessment of the events of 2008, see the 2008 Winter Review at https://www.ea.govt.nz/assets/dms-assets/409Winter-Review-Report.pdf

the time a formal regulator was present in the market (2004) there have been 18 claims of UTS, of which 3 have been upheld and resulted in changes to final prices[51], and one is still pending an investigation[52].

While not a classical intervention per se, for a long period of the market Transpower would address N-1 security shortfalls in real time by relaxing the reserve constraint (ie the market shifted below N-1, rather than Transpower conduct pre-contingent load shedding). While this was a pragmatic decision, it usually meant that final prices went down, not up, from constrained levels, as generation was released from the reserves market. This was addressed by the Electricity Authority through the scarcity pricing regime[53] which is now contained in Part 13 of the Code, introduced in 2013.

5.2 Current pertinent concerns about intervention

As part of the survey outlined above, questions were asked about the degree and mechanisms by which participants believed prices were either politically influenced, or subject to a threat of political intervention.

When asked about political and regulatory uncertainty, a core issue for gentailers surveyed above was the need to achieve a sufficient degree of market stability needed to underpin the significant investment[54] required from generation investors to achieve very high renewables. There were a number of concerns expressed about regulatory and political uncertainty in the current market environment that made pricing evaluation, offering strategies, risk management and investment planning more challenging:

- Uncertainty about potential breaches under the High Standard of Trading Conduct rules
- The risk of continuing UTS claims impacting prices
- The risk of ad-hoc political intervention to specific market events, beyond the Authority's consideration of a UTS (e.g., August 9th)
- Slow progress on gas industry information disclosure, leading to an asymmetry in information between gas market participants and non-gas market participants[55]
- The uncertainty introduced by investigations into e.g. NZ Battery that impacted some investment decisions being made right now, although no specific examples were provided.

All market participants agreed that the influence of these factors was often more subtle than, say, direct intervention in the workings of the spot market (such as the conservation campaigns and use of Whirinaki in the previous decade as outlined above). Rather, the perceived risk of intervention influenced the way decision makers were thinking about behaviour in the spot, contract and investment markets.

6 Overall insights

Below we draw out insights from the analysis and surveys above. Many of the themes below are quite interconnected, reinforcing that potential improvements to risk management need to be considered from a systems perspective; it is quite possible that small changes could have quite

[51] April 2004, March 2011, November 2019
[52] August 2021
[53] See https://www.ea.govt.nz/operations/wholesale/spot-pricing/scarcity-pricing/
[54] The Climate Change Commission's estimate of 12TWh of renewable generation investment required by 2035 was noted by participants. Estimates prepared by Gluyas et al for MDAG suggest this requires an increase of ~30% debt ($1.9b) and a ~20% increase in equity ($5.7b) over the current listed generators current levels.
[55] Especially since hydro information disclosure has been significantly more advanced for a number of years

material effects across the risk management "system". We also note that it is simply not possible to summarise everything that was said in the interviews: the richness of the conversations meant that many topics were traversed, and our selection below is the result of a subjective analysis of two factors:

- It's relevance to our objective – i.e., the confidence with which we expect market participant's risk management practices to adapt to an increasingly volatile world, and
- Issues that were raised by more than one or two participants[56].

As an overall reflection, though, very few participants spoke at length about how risks management would work in a 100% renewable world: their principal focus was on the nature of the transition to 100% (or, at least, very high renewables). This may have been because of their views about when the transition would be complete, and what the nature of the final system would be. In this respect gentailers were most vocal about the importance of how the progressive decommissioning of the thermal fleet should be managed (e.g., according to an agreed plan, or driven by owners' interest), and whether some (infrequently used) thermal fuel and plant should be retained in the system to manage risk in the longer term (without going to 100% renewables). Beyond this, though, there was general acceptance about there being increasing volatility in the transition, although views on the nature of that volatility varied.

6.1 Key themes

6.1.1 Risk management has improved over the past 10 years, and there is confidence that it will continue to improve.

Before the market commenced in 1996, the electricity supply chain had pricing mechanisms, but these were restricted to a week-ahead spot price determined by a pseudo-merit order "market" by a near-monopoly generator, with a capped price of 15c/kwh. There were no tradeable risk management instruments: ECNZ had the sole view of wholesale risk and was the only (wholesale) risk manager, using its internal mechanisms to translate views on risk into price (and vice versa). By contrast, we now have transparency and rules on how spot prices are formed, a wide diversity of participants forming and trading views on fuel, volume and price risks. These views are informed by a range of models and relatively deep data series, with risk management products – some standardised, some able to be customised - which are traded between market participants and span almost any conceivable horizon (within reason).

All of the market participants spoken to agreed that their risk management had improved over the past 10 years. It is worthwhile reflecting that, in the independent retailer space, one of the retailers spoken to didn't exist in 2010 (neither did the NZ electricity products on the ASX) and has achieved a significant degree of sophistication in that time. Market participants have developed (e.g., swaptions) and traded (ASX) products that didn't exist in the previous decade. The data presented in Section 3.4 illustrated clearly that trading volumes have increased through the period; even adjusting for market making activity, independent retailers have grown hedging activity commensurate with customer growth.

There was also general acceptance that risk management practices would continue to adapt and improve in the future. However, there were differing views as to which aspects of risk management (modelling, analysis, policies or use of products) would improve: non-gentailers were cautious or

[56] While many interesting points were raised by one or two, we have not reported these as we could not represent the views of the remainder of the cohort or overall set of participants.

negative about the market's ability to evolve the suite of products needed for them to adapt to an increasingly volatile world. But there was awareness across the cohorts that there is a spectrum of ways in which exposure to risk can be measured and modelled, and those less sophisticated could conceptualise a path of progression to better risk management.

6.1.2 The current product suite is mostly adequate for risk management, but views varied on pricing and liquidity.

Adequacy of product suite

Most market participants saw the products being traded currently as adequate both now and in the near future, but rather that the issue was the liquidity (as evidenced by Figure 10 below) and/or pricing of some of the profile-related products that was the concern. Further, many cited the development and increasing activity in the FTR Market (see Figure 8 above), and swaptions and "superpeak" contracts in the OTC market[57] as evidence that the market (including working with the regulator) was able to develop products to match demand.

Participants in both the independent retailer and gentailer cohorts saw an increasing need for cap products in the transition to 100% renewables, as a way of managing peak risk. However, the perceived importance of this risk relative to dry year risk (and thus the need for dry year risk products, such as swaptions) varied: Independent retailers saw capacity risk as the main risk to manage, while gentailers saw dry year risk as the issue to be most concerned about.

In many ways, this difference is unsurprising:

- independent retailers are (currently) most exposed to peak issues due to the difficulty of hedging their profile (which manifests most at peak times). Further, their hedging policies[58] likely drive them close to 100% hedged (on volume) around 6-12 months ahead of time, leaving little residual exposure (other than peak, or as a result of unexpected customer growth) to a sustained period of significantly elevated prices resulting from prolonged low inflows. That leaves low residual incentive to purchase dry-year insurance; the primary residual exposure is still profile-related and thus a major concern at load peaks[59];
- All major (and some smaller) gentailers have hydro as a fuel, hence are physically exposed to dry year risk ie., their physical portfolio is likely to be materially shorter in a dry year[60]. Equally, even in a dry year, the flexibility of hydro is still mostly available to manage intra-day volatility. Hence they have a heightened desire to hedge a prolonged energy exposure that may or may not occur in any given year, and a swaption contract provides that functionality.

[57] A number also mentioned a desire to see further progress made in respect of EnergyLink's flex-CfD product

[58] At least, the hedging policies we were aware of both within the participants interviewed and in wider advisory work

[59] We note that this is a feature of the current market fuel mix, which includes a large degree of flexible fuel (water, gas and coal). As gas and coal is removed, the profile of prices over the day and week may less resemble the load profile and more resemble the rhythms of the weather (wind and solar). While, in winter, availability of solar would reinforce the load profile (as observed with the duck curve in other countries), a predominance of wind with little apparent diurnal profile may mask the underlying load profile.

[60] To reinforce the difference to the exposure of retailers, if a retailer's underlying hedge book shrunk (in volume) in a dry year, they would be similarly incentivised to seek swaption-type cover. But, of course, this is not the case, although the customer compensation scheme arguably provides some incentives here.

Some (e.g., Gluyas, 2020[61]) have advocated for tradeable cap products that mimicked the SRMC of slow and fast start peaking plant as a way of capping holders' short-term[62] price risk and underpinning investment in firming plant.

As outlined below, some participants saw the need arising soon to find ways for developers to firm variable renewables (VRE, principally wind and solar), in order for them to meet the cost of firming directly, but also make the combination of a variable PPA and firming product more attractive to the retail market. While no participant specifically referenced them, we note that firming derivatives to complement renewable PPAs are being developed internationally[63].

Liquidity

However, views varied on liquidity. Independent retailers were frustrated by declining liquidity in peak and option futures on the exchange, where no market making requirements exist, as well as an increasing reluctance to price similar products in the OTC market (including caps). However, a number of gentailers indicated that they either have a formal or informal policy of pricing every OTC request from the market, and saw - at best - infrequent requests for pricing of caps, therefore questioning the depth of demand. Both views could be true, if retailers have now abandoned seeking cap prices as a result of consistently perceived excessive prices in the past.

That said, some gentailers were supportive of listing cap products on the exchange, subject to demand being confirmed. While they admitted they hadn't engaged with users since prior to COVID, the ASX also suggested user demand for caps appeared very limited to them, also citing the potential high cost of margining for cap products (given it would have to consider events such as the prices observed on 9th August 2021). The ASX is currently consulting with its Australian user group on the value of peak electricity futures and seeing more demand for a "superpeak" specification[64].

The current low liquidity for peak products is concerning for independent retailers, as the inability to achieve shape within their physical portfolio is a key disadvantage they face relative to vertically integrated competitors, which they see as a structural[65] impediment to greater liquidity. Figure 10 illustrates the relative prevalence of peak products (to baseload) in overall open market interest. At its highest volume in 2015, peak product open interest was 107GWh, which, given non-VI customer numbers at the time, equated to 1.78 MWh per customer. While barely detectable in Figure 10, it could still plausibly be one quarter's peak consumption of an average residential consumer (7-8MWh annually). Without accounting for how many years this open interest covered[66] it is difficult to gauge whether this is a reasonable assessment. However, by mid-2020 this had dropped to

[61] Gluyas, N, *An equity analyst perspective on capacity markets in NZ*, Discussion document for MDAG meeting, 21 April 2020

[62] Gluyas' illustrative product(s) were 1MW caps based on the weekly time-weighted average price (rather than a half-hourly cap) and had strike prices of $100/MWh or $125/MWh. Simulated payoffs suggested a $125/MWh cap would be revenue adequate (on a $/MW-year capacity basis) for Huntly for FY21-FY23. Gluyas concluded that, in this way, these products would be a way of converting actual market scarcity valuations into reserve capacity, as preferable to "risk-averse procurement of excess capacity".

[63] Solar and wind firming derivative products have been developed in Australia. See https://www.energycouncil.com.au/analysis/firming-renewables-the-market-delivers/

[64] The ASX suggested they may run a similar consultation with its NZ user group.

[65] Most independent retailers mentioned the forced de-merger of VI firms as the only alternative to market making for achieving liquidity in flexible products. That said, we note the voluntary demerger of Trustpower first via Tilt and then full demerger. This shows that voluntary vertical separation is not impossible.

[66] ASX data suggests these contracts were spread (unequally) across two years.

0.12MWh per non-VI customer[67], which in no way could possibly represent a plausible estimate of peak winter coverage for non-VI retailers. Below we also present in Figure 11 and Figure 12 market volumes traded in options and caps. As discussed above, gentailers provide the primary liquidity in options. Cap products have only recently emerged.

Figure 10 – Baseload and peak contract open interest on ASX, 2010-2021. Source: Electricity Authority.

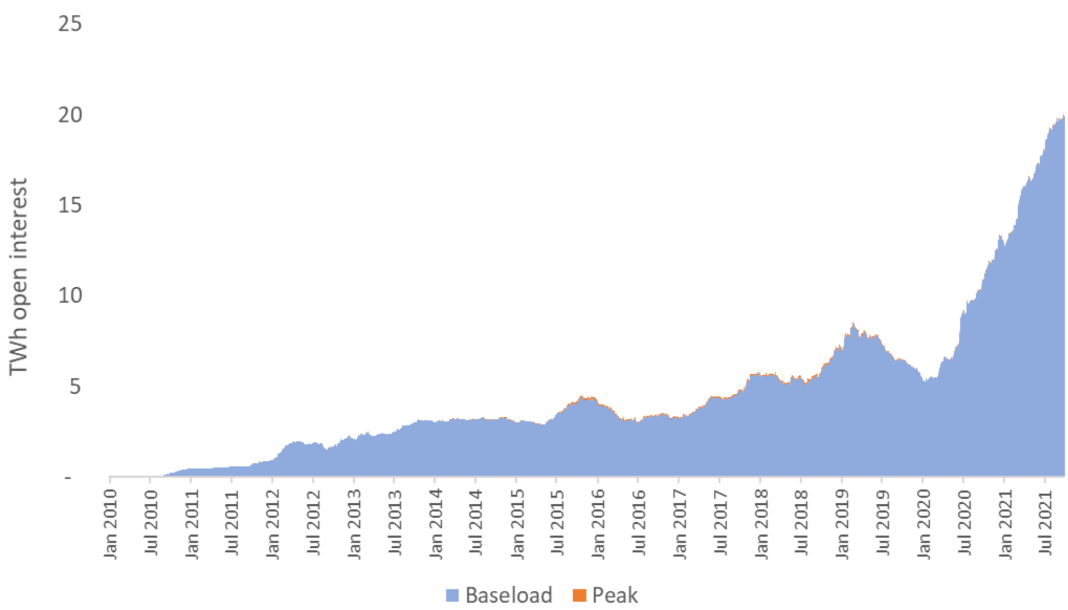


Figure 11 – Total monthly traded volume in contracts classified as options, all markets

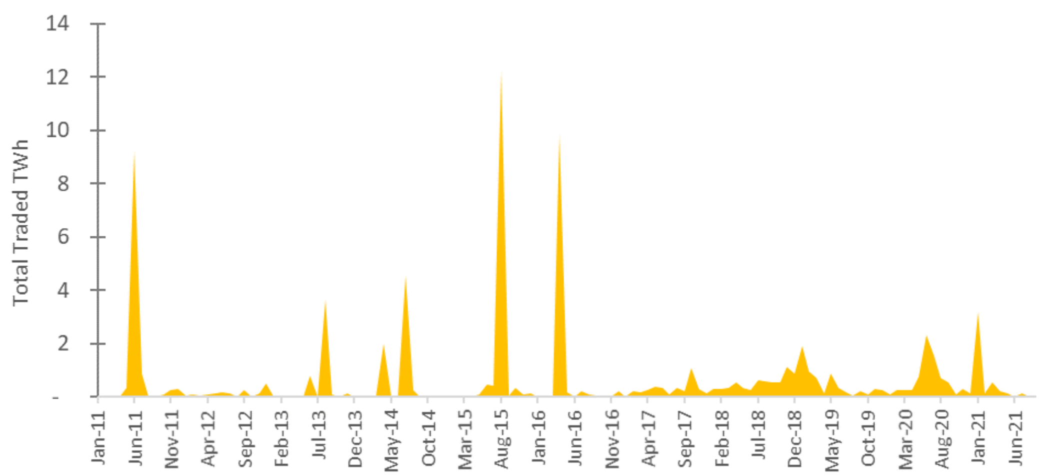
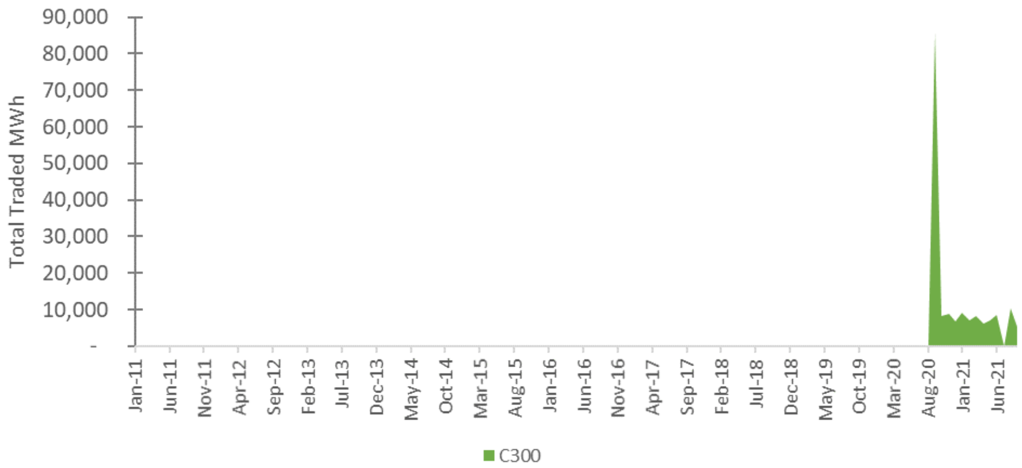


Figure 12 - Total monthly traded volume in contracts classified as OTC caps

[67] Again, spread across two years



The measures proposed to address the low liquidity in shape-related products fell into two categories:

1. Introduce market making in peak contracts (and potentially caps or options) on the ASX[68][69]; or
2. Rely on, and potentially introduce higher disclosure requirements in, the OTC market

Option (1) was not a view expressed by all parties in the independent retailer cohort. The main concern held about market making in peak products was that the retail purchase profile varied around the country, and varied by season, and thus a single product definition risked limited demand[70]. It is a design question as to whether listing a "superpeak" product instead would have the same challenges. Subject to the ASX reservations regarding initial margins, a half-hourly, daily or weekly cap product probably lends itself more to a standardised design and listing, potentially with market making. A further consideration is whether there is a cap product that better resembles the type of firming plant required by a 100% (or close to) renewables world than e.g., a quarterly strip of half-hourly caps, that might incentivise purchasers to move away from baseload hedges as a primary form of managing exposure. Ultimately, the design of a product that achieves this would have to balance the swaption-style features that would underpin firming plant, and the peak-based exposure of a residential profile, while also achieving sufficient liquidity and affordability from a margining perspective.

Regarding option (2), there is evidence that the OTC market has evolved a number of products to match the nature of price and volume risk in the NZ market. However, if the OTC market is going to be relied on for the development and trading of tailored risk products, it is currently challenged by the problem of silent evidence – that is, the only evidence for liquidity are deals that were made; there is no evidence base for deals not made, and/or requests for pricing that were declined. There may be some opportunities to improve monitoring, market surveillance and efficiency of the OTC market (e.g., moving to a centralised platform), although some studies in other markets suggest the

[68] The EA's consideration of market-making in peak ASX contracts was a recommendation of the 2015 Wholesale Advisory Group "Hedge Market Development" paper. The issue was also a key feature of a dissenting view of two WAG members, outlined in the report.
[69] Given the concerns about the cost of participation in the ASX outlined below, this approach relies on the ASX forward curve creating additional liquidity in OTC markets.
[70] One retailer cited the emergence of the "superpeak" product as evidence that the ASX peak product was not meeting retailers' requirements, where the OTC market could.

costs outweigh the benefits[71]. Whether these factors apply equally to the NZ electricity OTC market is beyond the scope of this study. However, we do believe there are a number of improvements that could be quickly made to the hedge disclosure regime, primarily around the nature of information that is collected[72].

Pricing

Finally, a number of the frustrations of independent retailers actually related to the high pricing of risk products (rather than liquidity). Commensurately, some gentailers were similarly frustrated at the low willingness to pay. Caps and swaptions were the primary target of these views. Together with peak contracts, we refer to these as "flexibility contracts".

A gap between the willingness of buyers and sellers for products that reflect system flexibility is a concern as an increasingly renewable system will commensurately increase the value of flexible resources. While the underlying theory of energy-only markets suggests the revenue adequacy of the optimal mix of plant will be supported through spot pricing outcomes alone, the issues of e.g., "forecastability", risk and the need for a firming plant to collect a sizeable proportion of LRMC-supporting revenue in an infrequent dry year means that the contract market takes on a greater importance to underwrite investment in flexible plant[73] in a volatile environment.

It is not clear to us why there is a perceived gap between the buy and sell prices of flexibility contracts (noting that sizeable swaptions have, in fact, been traded between some, but not all, major gentailers). This is not just a concern for the grid-connected wholesale participants; given the increasing importance ascribed to flexibility through distributed energy resources (which face many of the same issues) it could also become an impediment to the emergence of DER markets. Potential reasons could include:

- There is a difference in the relative risk aversion between the buy-side and sell-side. We would be surprised by this, given the greater ability of gentailers to fund periods of market stress.
- The sell-side are currently basing their pricing of flexibility contracts as much on their valuation of the plant underpinning it, as the risk management value to purchasers.
- The buy-side see a different risk profile to the sell-side. This could be an educational or experience shortfall, but NZ now has a good history of prices, including a number of "dry" years, although these are somewhat infrequent and participants new to the market may not have direct experience of this for some years. We also note that the periods of heightened

[71] See e.g., Chow, Tan and Wong (2016) "Liquidity and Policy Analyses for Platform Trading of OTC Derivatives: A Perspective of Smaller Markets", Staff paper 54, Monetary Authority of Singapore. The authors include in their paper a number of metrics for monitoring liquidity in OTC markets, although these do appear to rely on a degree of standardisation in products.

[72] For example, in NZ's current hedge disclosure system, there is no distinction between peak, superpeak, shaped/flex or baseload products within the "CfD" category. Standardisation of some contracts (specifically baseload and peak contracts) was a recommendation for investigation by the Wholesale Advisory Group in 2015.

[73] See Read, E. "An Economic Perspective on the New Zealand Electricity Market", (2018) s2.3-2.7. Specifically "*Thus, while there may be many steps in between, the fundamental role of contracts is to bridge from the LRMC-dominated world of physical (investment in) generation capacity, through the SRMC-dominated world of spot market trading, and on to the LRMC-dominated world of physical (investment in) consumption capacity, both industrial and domestic.*" p22/23

volatility (prior to 2018[74]) largely resulted from transient physical reasons[75] rather than a permanent feature of the market. Further, extreme high prices have been subjected to (in three cases, successful) UTS claims which saw prices reset. This may result in participants lowering their assessed likelihood of short-term price risk. Further, as discussed in Section 5.2, conservatism on the part of generation owners in the face of regulatory/political uncertainty and risk may be supressing the high end of the price duration curve.

- One participant raised the moral hazard that was identified during the market design phase in the 1990s: that the purchasers that fail to hedge do not face the full consequences of contingent load shedding by Transpower.

Assessing the reality of the reasons is beyond the scope of this study, and we have been unable to uncover any evidence for the reasons proffered above. However, given the importance of hedging to providing revenue adequacy for plants critical to firming, giving greater transparency and evidence to the buy-sell "gap" is worthy of consideration. As was highlighted in the early market design period[76], contracts are as much about incentivising the right mix of plant as they are about insulating participants from price risk. A continuing disparity in views on the shape of the price duration curve may not be a problem, and may reflect the reality of a large incumbent power station (Huntly) that was inherited by the market. However, a gap would be of concern if the underlying reasons suggested that the market's ability to invest in the right mix of plant through time was likely to be compromised.

6.1.3 The ASX has been a significant step forward for risk management, although trading products through the exchange is an increasingly costly way of managing risk.

The emergence of ASX was widely seen as one of the most significant advances in risk management for all participants. Not only were parties able to secure a set of risk management products on the ASX, the transparency of the ASX curve had enabled all market participants to have a reference point for valuing products traded in the OTC market. Thus the risk management impact of the ASX goes well beyond participants' open interest on the exchange itself.

However, while not all participants raised the issue, there was agreement across cohorts that the ASX had become an expensive channel for hedging, principally in the form of initial margins. The cost of funding initial margins from working capital is seen either as a barrier to direct participation or a feature which draws funds away from other uses of capital. Secondly, it is additive to the spot market prudentials that must be posted by purchasers, despite the fact that hedging on the ASX is in large part employed to avoid the worst outcome of risk – wholesale market default. It is difficult to see how this issue can be resolved, due to the two prudential funds being held in separate jurisdictions[77].

Initial margins are a central part of the "gold standard" (as described by one participant) credit service provided by the exchange. Initial margins for derivative products are set by the ASX with the

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[74] It is unknown whether the last 2-3 years is equally seen as transient and unlikely to be repeated, although the recent investment by all purchasers spoken to in understand coal and gas suggests they will be reasonably well informed about the nature of the current issues.

[75] The most prolonged period 2007-2012 resulted from the failure of Pole 1 of the HVDC which was remedied through Transpower's investment in Pole 3. Also, there was a progressive maturing of the scarcity pricing regime under the Electricity Authority which improves the degree to which scarcity of energy is reflected in final prices.

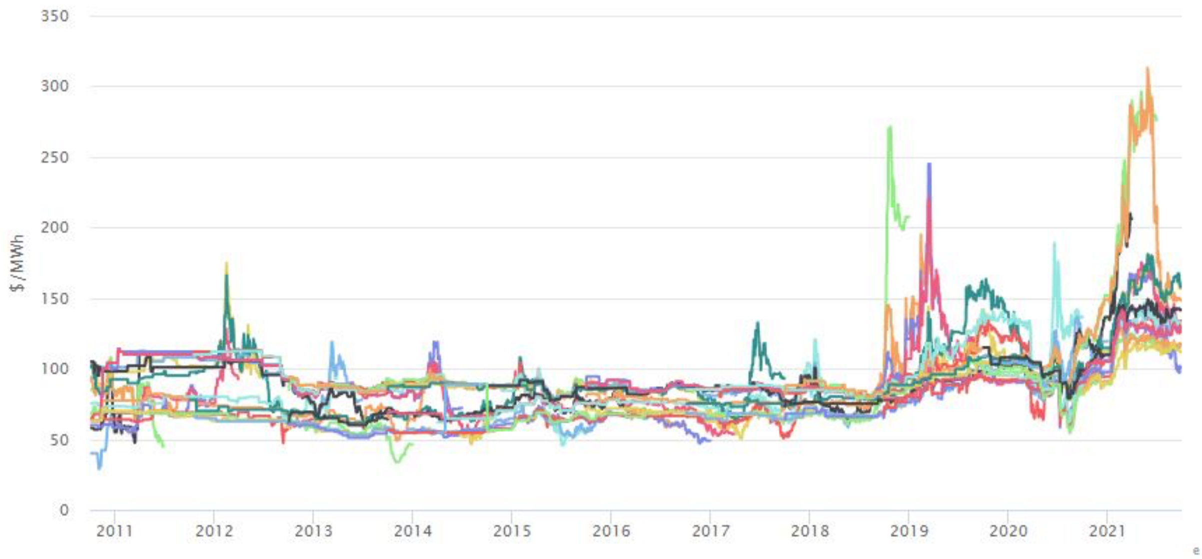
[76] See Section 2.1 and especially reference in footnote 6.

[77] We understand that there have been previous attempts to resolve this with the ASX, but the jurisdictional issues are a major stumbling block.

widely used Standard Portfolio Analysis of Risk[78] (SPAN) margining methods tool. We raised this with the ASX directly and they confirmed that margins had increased as a result of the coincident effect of three primary reasons: increased volatility, an increase in the assumed number of days to close a position, and – due to the fact that margins are calculated as a function of the underlying price level - the increase in the futures prices. The SPAN calculation is somewhat complex, effectively assessing the maximum expected loss for a product if the holder defaults, taking into account different market conditions (principally volatility), and the speed with which the exchange can close out the defaulting position under those conditions[79]. It is therefore understandable that SPAN margins have increased, since both the volatility and the price of electricity futures have risen over the past three years (Figure 13).

That said, there may be ways in which some variables in the SPAN calculation can be improved[80].

Figure 13: Settlement Prices for all short-dated NZ electricity futures since 2010 (Source: Electricity Authority).



In the context of the (formulaic) increase in the cost of credit management on the ASX – partly driven by recent market conditions, it is interesting to note that one independent retailer perceived it unreasonable that the OTC credit requirements from gentailers had commensurately increased. The increase in OTC credit requirements was validated by a broker who participated in the survey[81], but the issue was not raised by the other participating retailers. The perception of unfairness possibly arises because the increase in OTC credit requirements was being driven by a large competitor, rather than an independent exchange.

If OTC credit requirements have, in fact, increased during the last 3-4 years of increased price levels and volatility, it will be interesting to observe whether these are relaxed should the ASX initial margins reduce.

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[78] This method was developed by the Chicago Mercantile Exchange in 1988, which calculates the maximum potential loss for a portfolio of derivatives grouped by product.

[79] Obviously the potential loss to the exchange increases as the number of days it might take to close the position out in the market increases – especially in a volatile market.

[80] SPAN is directly connected to market liquidity. One comment made by an advisor to the project was that the current market making arrangements may be able to be improved in a way that affects the SPAN calculation.

[81] One generator strenuously denied there had been any change to their credit requirements

6.1.4 The PPA market is becoming more active, but market depth and variability of generation is an issue

The majority of participants – across the cohorts – commented on the PPA market. The PPA market has always been present and active, especially for independent generators (primarily wind and geothermal) but, as a result of reducing costs of both grid-scale solar and wind farms, a number of new independent developers have emerged.

A number of participants commented on the low pricing (relative to the forward curve) of VRE PPAs, but most recognised that these came at a cost. As discussed above, the profile of wind and solar generation does not match the load profile (generally, and especially residential) which, for a retailer, leaves a residual purchase profile that would be very difficult to hedge using the products available today; particularly with wind, the shape of this profile would be unpredictable. This may result in a further impediment to independent retailers competing in the PPA market. Moreover, as wind and solar increase in overall penetration, to the extent that sites' production is correlated PPA buyers potentially face a volume-weighted premium on the spot cost of this residual profile. This premium will be highly uncertain, and therefore presents a risk that needs to be managed.

At this point in time, this may not present a major issue for the PPA market, for two reasons:

- While independent VRE projects are relatively small, the PPAs may be able to be absorbed into large industrial and gentailer portfolios without causing a material change to their exposure and thus risk, and
- As indicated above, if the influence of correlated VRE production on the spot price is low, the residual purchase profile may not see a VWAP premium.

As the volume of VRE PPAs grow, though, so will the implied "cost" of firming. This cost could be made explicit through the development and market pricing of firming derivative products to suit VRE, else it will simply be inherent as a discount in the market's valuation of the PPA contracts. The lack of transparency around this cost may result in independent generators being unsure as to whether they are being paid the fair value of their output. Whether this cost will be as material as that observed in other jurisdictions is an open question – NZ's market design incentivises our significant storable and flexible hydro plant to respond to the variability of VRE in a way that the slow-start thermal and baseload nuclear power stations in these other systems cannot. Even under a very high renewables future, that flexibility will continue to be present, at least in the short term (hours, days and potentially weeks).

We note that solar and wind developers may elect to manage their own variability physically, by co-locating batteries onsite, as has been seen elsewhere in the world. As outlined above, this may be achieved synthetically through a combination of baseload and cap contracts for example. Other jurisdictions are evolving derivative products which effectively provide the mirror of a wind or solar profile, thus leaving the owner of a PPA with something resembling a baseload hedge (at least over the short term, e.g., a day or a week). Whether this is a potential solution for NZ remains to be seen; such derivatives still, ultimately, need flexible plant to be sellers. More broadly, comments made by some participants indicated that the risks across all PPAs may be able to be aggregated through a collective insurance scheme[82] may be worth pursuing.

However, it is worth noting that integrating even modest VRE PPAs into a small retailer's portfolio presents a challenge even today – independent retailers are likely to be dominated by a residential

[82] It is not clear what event would be insured here.

profile (solar PPAs will provide no production at winter peak times), and they do not have the flexibility within their overall portfolio that gentailers do. Further, independent retailers may find it challenging to commit or meet the credit requirements for 10-15 year contracts, especially if the PPAs are likely to make up a material component of their purchases: uncertainty about the level of future prices may make retailers reticent to commit for such a long period of time, for fear of becoming uncompetitive if market prices are lower than contracted[83].

Alternative buyers include industrials and vertically-integrated generator retailers. The same concerns about firming cost and future price competitiveness apply to industrials, and gentailers expressed concerns about how much of their "flexibility capacity", which could provide firming, is already absorbed by their own retail load. Some gentailers will no doubt have their own development ambitions, and will trade off a long-term arrangement with an independent generator against their own ability to execute generation development projects.

The combination of retailer, industrial and gentailer preferences regarding purchasing of PPAs may mean the market has limited depth until parties become more comfortable with pricing. Alternatively, seeking greater depth in more liquidly traded products (baseload and shape-related products) may give intermittent developers other options to hedge their load, albeit at a higher cost in terms of risk management.

6.2 Conclusions

It is clear from the evidence that risk management across market participants has evolved and improved substantially since the commencement of the market, and especially over the past 10 years. From the inception of the market it was understood that hedging by market participants was a crucial corollary of efficient spot market trading, retail competition and new investment.

At an overall level, we were unable to uncover any evidence that there is a concerning, systemic exposure to risk across the market; in fact most of the observable data shows an increasing, and adapting use of hedge products.

This, by no means, suggests that the hedge market is perfect. We summarise below what we suggest are the four key issues for the contracts market to properly evolve and adapt to a more renewables world:

i. How to reconcile the diverse and sometimes conflicting messages about the availability of, and demand for, profile or flexibility related products (caps, peak, superpeak, dry year products); particularly
    - whether the availability concerns reflect **low liquidity or unsatisfactory pricing** (which could be determined through greater monitoring of the OTC market, including requests for pricing);
    - if **liquidity**, given the importance of profile-based products to both assisting risk management and underpinning investment in the right types of resources for a very high renewables world, how should liquidity be improved? Should the OTC market continue to be the primary channel for development and liquidity of shape-based products, or is there a case for amending existing product specifications on the ASX (e.g., move from peak to superpeak) and/or introducing new products (e.g., caps), potentially with market making obligations (noting the complexity and potential cost of market making in more sophisticated products);

[83] Although we expect contract price reset mechanisms should partly address this

- if **pricing**, whether any gap between buy-side and sell-side valuations of these products is material; and, if so, whether the underlying reasons for any gap points to wider issues with the way risk is evaluated and priced by market participants, and
- Whether any **risk evaluation biases** identified are compounded or improved by a world with more volatile spot prices, and how this is likely to impact on contracting, and in turn flow through to new investment.

ii. Some participants' apparent inability to reconcile some hedge prices to their own internal forecasts, or to other transparent hedge prices (ASX), and that this may be undermining trust in the market – we are unsure whether market education or just greater transparency of the premia that exist between different products is needed here;

iii. In respect of hedging new intermittent generation projects, whether there needs to be (a) any market development (e.g., development of firming derivative products) to more explicitly evaluate the costs of firming VRE, or (b) the market will provide that signal through PPA buyers' valuations of PPAs as firming becomes more challenging and costly, assuming the market for PPAs is subject to sufficient competitive tension, or (c) developers will self-provide physical or financial firming in the form of co-locating batteries or demand response onsite, or by taking on some component of wholesale risk and using firm hedge products; and

iv. Given the importance ascribed to the ASX by so many participants (transparency and liquidity), how to evaluate whether the current heightened costs (initial margins) borne by ASX market participants are efficient and reasonable (if they are even permanent), and whether the cost of participation is preventing access to hedge products in a way that is materially compromising parties ability to manage risk prudently. It is important to understand that the ASX is not expected to be the single solution to all parties risk management needs. This may be a topic best left until the Authority has concluded its move to commercial market making contracts, which should make explicit this cost.

We observe that lack of transparency in the "dark" OTC markets (which include PPAs[84]) makes it difficult to assess the materiality of the frustrations expressed by some parties. However, it seems likely that these questions will become more pronounced as the market transitions to a more renewables world with its associated increase in spot price volatility. It follows therefore that we should test further whether these four key issues are real and, if so, assess possible remedial options, which could include additional monitoring and transparency of OTC markets, respecting the commercially sensitive nature of contracts.

To this end, we note that MDAG has engaged Sapere to further explore how parties are likely to respond in risk management terms to a more renewables world, applying a transaction cost framework.

[84] As an illustration of the transparency that is available in respect of PPAs in Australia, see https://www.energetics.com.au/insights/knowledge-centres/corporate-renewable-ppa-deal-tracker. In NZ, PPAs are lodged through the hedge disclosure system but within a wider category of FPVV contracts – PPAs themselves are not afforded their own category.