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Derivatives and Hedging Practices in the Australian National Electricity Market

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Abstract
This article expands on the seminal policy work by Anderson et al. (2007) and explores the impacts of a changing energy mix on derivatives and hedging practices 15 years on from their work in the Australian National Electricity Market (NEM). The Australian electricity market has undergone vast change since 2007 as increasing amounts of variable renewable energy (VRE) has entered the market. This can have a significant impact on the contracting patterns and derivative use of participants. A survey of 21 market participants was undertaken to determine how they conduct derivative trading and hedging of their portfolios. Additionally, participants views on the current state of energy policy and operation of the market was determined. The results showed participants continue to use derivatives as was previously studied with increasing use of PPAs for VRE contracting and a sharp drop in use of traditional peak contracts. However, there was concern from participants future ability to hedge portfolios as liquidity in the derivative market shrinks with exiting dispatchable plant. This poses a difficult path for policy makers and regulators as a functioning and active derivative market is integral for the operation of an energy only market such as the NEM.

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1. Introduction

Electricity markets globally are undergoing an immense change with the exit of traditional dispatchable thermal generation such as coal and gas in favour of variable renewable energy (VRE). This change will have profound implications for the forward derivative markets which support real-time spot electricity markets and are an important area of concern for policy makers. An active derivative market provides a forward view on the requirements for new plant and expected prices paid by electricity customers. Without these, a market is likely to become opaque and it can be politically difficult to manage for policy makers and regulators.

Issues related to forward markets are increasingly present in Australia's National Electricity Market (NEM) where VRE sometimes makes up over 100% of generation. In conceptualising the structure of a productive derivative market under a future dominated by VRE it is important to understand how different players in the current market are changing their use of 'old' market products and incorporating 'new' products within the framework of current policies and regulations. One way of gauging the impact policy decisions are having on the market is to ask these market participants. However, due to the sensitive nature of electricity trading gauging market sentiment can only be done through anonymous surveys; this is the focus of this paper.

A unifying feature of electricity markets globally is that they are complex, with structures differing from one country to another (Stoft, 2002). This complexity creates difficulties for policy makers to establish a suitable and active market structure. However, regardless of different market structures their commonality lies in the fact that electricity cannot be efficiently or easily stored in large quantities, therefore the bulk of supply must be matched to meet the required demand in real time (Wilson, 2002)[1]. This is further complicated because real time demand is often volatile with consumer use influenced by time of day and weather. This concept of matching supply to demand in real time makes electricity spot markets inherently volatile.

Several different types of market designs are used in electricity markets, ranging from day ahead markets to energy-only real time markets. The most common contracts traded globally are forwards, futures and swaps (the latter being a two-way Contract-for-Differences - CfD) (Deng & Oren, 2006). Some electricity markets may also trade various types of options, caps, floors, tolling contracts and other bespoke contracts (Deng & Oren, 2006). All markets, however, include some form of forward market for contracts or derivatives to support their operation. The spot or day ahead market provides generators with the price signal needed to determine unit commitment requirements (Wilson, 2002) while longer term commitments are made using forward contracts, which can either be for physical delivery of electricity or used as financial hedges. Contracts for physical delivery can only be purchased by generators, retailers or load serving entities as they are the operators who can physically deliver the electricity. Speculators can purchase contracts for physical delivery, but they must offset their position prior to maturity.

Alternatively, contracts can take the form of derivatives and be cash settled, which means anyone can participate in these markets (Bessembinder & Lemmon, 2002). Liquid forward or futures markets for power in electricity markets can be utilised to provide an adequate risk management tool for both generators and retailers alike as well as providing forward guidance on the need for new generating capacity. Additional derivative contracts, such as futures, forward contracts, or Power Purchase Agreements (PPA) provide the tools for financing this new generation. In spot markets, generators and retailers are exposed to spot pricing which can fluctuate due to the difficulty in and cost of storing electricity (Wilson, 2002). Electricity derivatives therefore are needed due to the incompleteness, and at times un-competitiveness, of spot markets which provide the real time balancing market to match electricity supply and demand (Wilson, 2002). If spot markets were perfectly competitive then forward

[1] At the time of research by Soft (2002) and Wilson (2002), batteries were not common in energy markets. However, batteries increasing prominence in energy markets indicates the increasing affordability of storing energy and therefore they are now a viable option.

markets could be organised around spot pricing, such that the forward pricing accurately reflects spot market activity.

Volatility from spot electricity markets results in derivative markets for electricity being vital in ensuring the continued financing and operation of generators, retailers, and large industrial consumers. Market participants must engage in the real time spot market for the allocation of supply and demand on an intra-day level with derivative markets being crucial in allowing market participants to manage the cash flow risk associated with volatile spot markets. In this way generators (a natural long energy position) match as a counterparty with a retailer (a natural short position) with derivative contracts offering a risk reducing mechanism for both parties. Derivatives for energy markets can be in power, reserves, transmission capacity, greenhouse gas emissions and environmental certificates. This paper will focus on derivatives for power and long term off takes such as PPAs.

This article is structured as follows. Section 2 reviews the relevant literature vis-à-vis forward markets and hedging practices of both generators and retailers. Section 3 outlines how the Australian National Electricity Market (NEM) operates in both the wholesale spot market and derivatives market. Section 4 outlines the methodology and results from a NEM participant survey based on previous research by Anderson et al. (2007). Using the survey results Section 5 outlines potential issues in the market and poses solutions for they could be addressed. This article concludes by offering how policy makers and market participants can actively improve potential flaws within the market.

2. The forward contract market and hedging

Hedging is a financial strategy that reduces the exposure to volatility in a market by taking offsetting positions (Smith & Stulz, 1985). Hedging is a natural component of a commodity market where the producers have the physical assets which makes them the 'long' party, while commodity consumers are the 'short' party, as the payoffs are negatively correlated to spot price outcomes (Skantze & Ilic, 2001). Electricity market design is more complex than a basic commodity market as it involves not only the producers who generate the electricity but also two 'types' of consumption industrial consumption which occurs across a range of scales as well as residential consumption. Whilst the end-to-end movement of electrons takes one path, the financial costs incurred and how generators are paid by retailers/consumers can be complex. In the simplest form electricity markets are designed to address the challenges of electricity system operation whilst providing efficient economic outcomes. This is done through exploiting utility constrained economic dispatch in conjunction with well-developed spot markets and a reliance on forward contracts (Hogan, 2016).

Historically, when utility companies were vertically integrated to include generation, retail, transmission and networks, financial hedging was not necessary. This was because the physical assets required for generation and transmission were largely underwritten by the consumer base in a monopoly franchise, with retail prices forming the hedge against these physical generation assets (Michaels, 2004). In simple terms, the risks had been internalised through vertical integration (Simshauser, 2021). The need for hedging in an electricity market comes from two linked sources; the first is that firms can benefit from hedging as excessive volatility increases financial distress and leads to suboptimal investment (Bessembinder & Lemmon, 2002) . Secondly, electricity markets are inherently volatile and highly uncertain due to the nature of spot markets arising from efficient dispatch of power, weather and periodic aggregate final demand.

Contract use by market participants occurs for a variety of reasons but without inherently long and short players being actively involved, the contract market would cease to exist. Traditionally retailers use derivative contracts such as futures, forwards, swaps and options to mitigate their revenue risk exposure to volatile spot markets. As retailers face spot pricing for their fixed tariff paying electricity customers in electricity markets. Conversely, generators are concerned if market prices fall too low. An increasingly common occurrence with increasing penetration of VRE, or with price spikes which are also becoming increasingly common (McConnell et al. (2013); Simshauser (2018)), at a time when generators cannot meet their contract requirements due to plant outages. Financial intermediaries commonly use derivatives as a way to speculate on market outcomes which also provides liquidity to derivative markets.

2.1 Retailer hedging

Electricity retailers buy electricity from the wholesale market or generate electricity from their own plants for re(sale) on the retail market. Retailers have an inherent need to hedge their contracted electricity usage as they are exposed to real time day ahead or spot prices whilst they supply customers with a simplified flat or peak/off-peak tariff (Bushnell et al., 2008) . Electricity markets are particularly unique, in normal commodity markets demand uncertainty can be managed through storage. Electricity storage is costly, meaning retailers must manage both quantity *and* price risk at the resolution of the trading interval, which in the NEM is 5 minutes (Boroumand et al., 2015). Hedging for electricity retailers takes place over two different time horizons, first a retailer must hedge the estimated quantity of supply for a customer at the customer purchase for each given period. Second, retailers are exposed to short term quantity risk over days, hours, and minutes due to customer load variations (Boroumand & Zachmann, 2012) . The approaches used to hedge these time horizons can be similar but tend to differ as the time horizon gets shorter.

Basic hedging for retailers can be done using two methods. The first uses physical assets to hedge the volume and price risk associated with consumers. This uses a vertically integrated or internalised approach whereby the retail portfolio is hedged using physical generation through the on-sale of generator output and costs to consumers. The second occurs over a longer time horizon and utilises long term contracts such as forwards or futures as a substitute for physical assets. The traditional method of retailer hedging is shown in Figure 1 where baseload swaps, peak + bespoke shape and cap contracts are used to cover the low, central, and high cases of load flex. The contracts used by retailers to manage the load flex have traditionally been provided by dispatchable thermal plant such as coal and gas. However, increasing VRE is displacing dispatchable plant and as a result changing the options for retailers' hedging products.

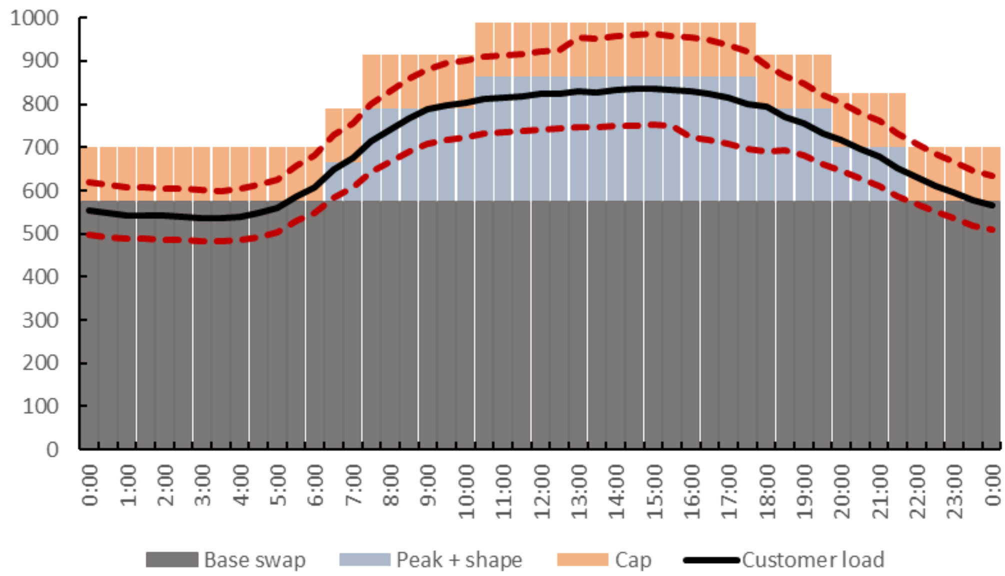

Figure 1 - Hypothetical method for retail hedging using only derivative contracts.

2.2 Generator hedging

The incentive for generators to hedge is very similar to that of an electricity retailer as the electricity spot markets they participate in are highly volatile. Good hedging practices provide more certainty over revenue, costs and margins buffering this volatility (Deng & Oren, 2006). It has been shown that a generator's behaviour in an electricity market can greatly depend on the competitiveness of the market in which it is participating. At a simple level, generators have an incentive to hedge their portfolio to provide more certainty over their revenues. If they are only exposed to the spot market they risk losing money if spot market prices, for a given period, are lower than their marginal running costs, and over time, their total cash costs including financing costs (Wolak, 2000). At the same time, generators may not seek to hedge all their expected output as in that situation they cannot take advantage of periods of high spot prices.

Previously, traditional electricity generators, underpinned by baseload generation through coal, have been dispatchable which allowed the use of conventional hedging products including forwards, futures, swaps, and options. As nations increasingly encourage and incentivise the uptake of VRE to decarbonise their electricity systems traditional forms of hedging for VRE generators are not always suitable (especially for stand-alone, non-portfolio assets). Conventional hedging products for VRE can result in adverse exposures to sustained spot price spikes, which in turn may lead to financial stress for an operator without a dispatchable firming generator (Flottmann et al., 2022). As a result of the potential financial stress for VRE operators, modernised contracting structures are required for adequate VRE hedging.

Currently the dominant mechanism for hedging VRE generators is through a run-of-plant PPAs or Contracts-for-Differences (CfD) as these have secure forms of payment for the generator that remove all variability in spot prices. As this form of hedging is typically taken out over longer time horizons (typically 10-15 years) the buyer of the PPA or CfD will invariably avoid exposures to very high prices cycles, but also suffer from missing out on decreasing electricity prices as more VRE enters the market (Nelson et al., 2012; Simshauser, 2019b). Instead, the buyer is left paying a fixed higher price as part of the PPA or CfD contract. Despite the potential risks of buyers paying more for their electricity under a PPA as renewable energy increases in the generation mix, they are still the preferred (and often necessary) form of financing and contracting for VRE in many markets (Gohdes et al., 2023).

Ingmar et al. (2022) investigated an alternative to government backed CfD's for new wind farm developments. They proposed a "financial wind CfD" to hedge both price risk and volume risk experienced by a VRE generator. In these contracts a generator is paid a fixed (inflation indexed) hourly remuneration independent of the generators actual production during those hours while the generator pays the holder of the contract (in their example, a government) the spot price (or zero if negative) multiplied by the hourly output of a reference turbine (which importantly is not the hourly output of a specific asset) (Ingmar et al., 2022).This instrument provides a payment to the contract holder in high-price and/or high-wind periods and a payment to the generator in low-price and/or low-wind periods which stabilises the generators total revenue (Ingmar et al., 2022).

3. Australian National Electricity Market

The electricity supply industry in Australia was initially organised through state owned vertically integrated monopolies but in 1994, the system started to transition towards the NEM, which was complete by 1998. The liberalisation of Australia's electricity market has been widely studied due to its success as measured by appropriate levels of new investment and decreases in wholesale prices (Lee et al., 2021; Moran, 2006; Simshauser, 2019a).

The NEM operates on the eastern seaboard of Australia across 6 states and territories: Queensland (Qld), New South Wales (NSW), Australian Capital Territory (ACT), Victoria (Vic), South Australia (SA) and Tasmania (Tas). The Australian Capital Territory is included in the New South Wales region to make up the 5 market regions within the NEM (Mayer & Trück, 2018). The regions are physically linked so electricity can be transmitted between adjacent regions of the NEM through interconnectors. This allows the movement of electricity when one region has excess supply to another region with unmet demand. The physical linking also allows regions to take advantage of price arbitrage, for example Tasmania via the Bass Link, can sell its electricity to Victoria during high prices and then import electricity during low periods (Moran, 2006). There are, however, limitations on the physical amount transmitted due to the limiting capacity of the interconnectors (Han et al., 2020). The NEM has a varying mix of generation sources which also varies widely between states (Table 1).

Table 1 - NEM capacity, fuel mix and peak load (AER, 2022).

Region	Installed capacity (MW)	Peak load (MW)	Fuel mix	Dispatchable capacity (MW)	VRE (MW)
QLD	16,100	10,135	Coal, gas, solar, wind, hydro	12,415	3,686
NSW	21,066	13,153	Coal, gas, solar, wind, hydro	15,638	5,428
VIC	14,994	8,976	Coal, gas, solar, wind, hydro	9,883	5,111
SA	7,225	3,120	Gas, solar, wind, battery	4,206	3,019
TAS	3,350	1,521	Hydro, wind, solar, gas	2,733	567

The landscape in the NEM has changed significantly since Anderson et al. (2007) through multiple areas, retail, generation and international exposure. In 2007 VRE accounted for only 6.2% of all NEM generation with nearly all of that in hydroelectricity. Whilst in 2022 VRE generation made up 34.9%, an increase of 420% in VRE generation over the past 15 years. The increase in VRE was driven by government policy and corporate decarbonisation goals which lead to investment of over $26.5 billion in VRE projects from 2016 – 2022 (Simshauser & Gilmore, 2022). Since 2007 most states have moved away from publicly owned retail businesses (apart from Tasmania and regional Queensland) and as of 2023 a large amount of retailing is conducted through a few major ‘gentailers’. The term ‘gentailer’ relates to companies who are major retailers but also major generators of electricity (de Bragança & Daglish, 2017). Whilst there are still independent retailers with significant load especially in the commercial and industrial (C&I) space, the big 3 gentailers (Origin Energy, Energy Australia and AGL Energy) control a majority share of the customer base, and importantly generation (Table 2 & Figure 2). There are still some pure play generators within the NEM owning legacy coal and gas plant in NSW, Victoria and Queensland. However, there are increasingly becoming more VRE and battery only generators and operators. Queensland and Tasmania are the last states where the state government owns 40% and 96% of the generation fleet, respectively.

Table 2 - Retail market share of big 3 gentailers compared to regional and tier 2 retailers (AER, 2022).

	Residential	Small Business	Commercial & Industrial
AGL Energy	22.15%	19.55%	14.35%
EnergyAustralia	14.94%	13.27%	13.49%
Origin Energy	26.93%	26.72%	28.45%
Regional & Tier 2 retailers	35.98%	40.46%	43.71%

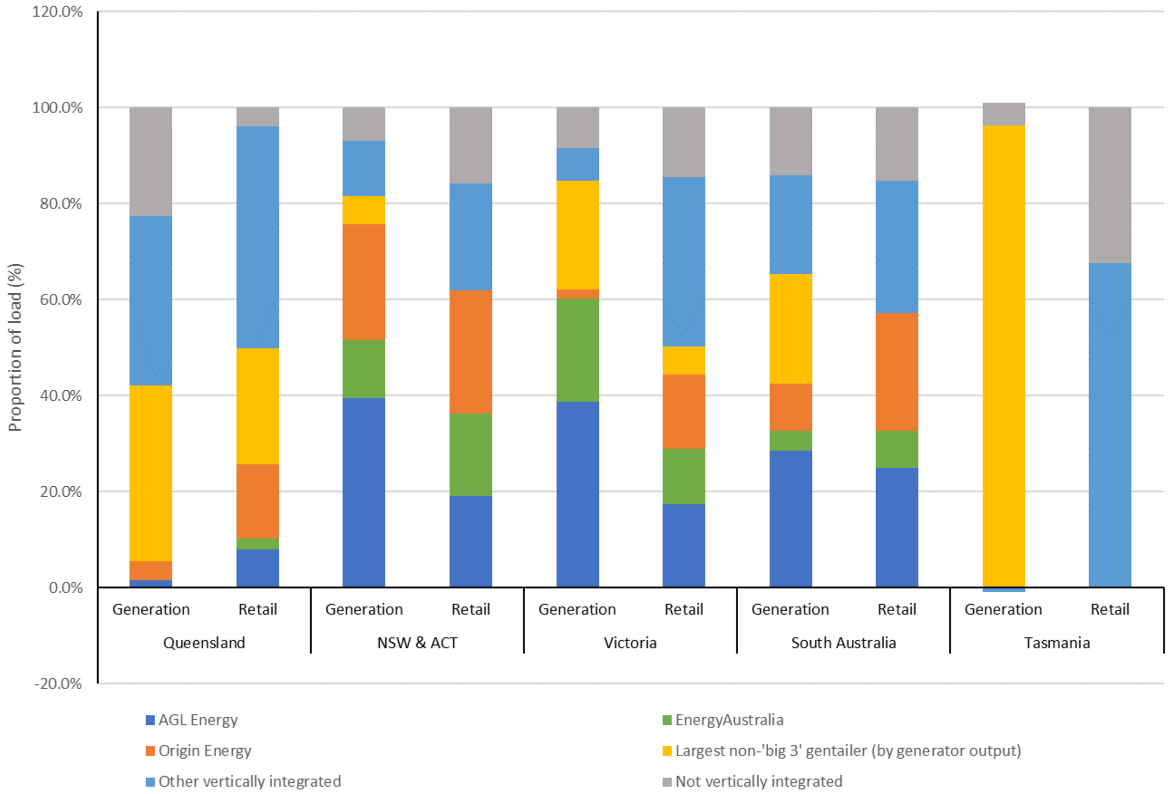

Figure 2 - Level of vertical integration in each NEM state showing how 3 major gentailers operate the majority of the generation in most states apart from Queensland and Tasmania where governments control the generation (AER, 2022).

Importantly for price setting in both the spot and contract market the NEM has remained exposed to international commodity prices for gas and coal. This has come about through the construction of three liquified natural gas (LNG) export terminals in Gladstone Queensland for export of coal seam gas from the east coast (McConnell & Sandiford, 2020; Simshauser & Nelson, 2015). As a result, marginal gas generators must now compete with export markets for gas which can drive up the short run marginal cost of gas generators potentially increasing the price of electricity. Additionally, many legacy coal plants were at 'mine of mouth', however marginal coal plants are not and must procure coal from the export terminals of Queensland and NSW. As international coal prices rise due to global macroeconomic conditions, it can cause the domestic supply of electricity to also rise, as marginal coal plants are purchasing fuel at international prices (Simshauser, 2023). The remaining Victorian coal plant stock does not suffer from internationally linked coal prices, as they use lignite (brown coal) which is not exported. In the wake of export linked commodities, current market participants in the NEM must also consider their exposure to international commodity markets. This became extremely apparent in the energy crisis following the Russian invasion of Ukraine in February 2022, which drove international coal and gas prices to 5-6 fold their historical average (Simshauser, 2023).

3.1 Spot market operation

The Australian Energy Market Operator (AEMO) operates the NEM's physical spot market as a real time wholesale market with an energy-only gross pool (Mayer & Trück, 2018; Simshauser, 2019a). The spot market is traded and settled on a 5-minute basis which allows dispatch and scheduling to be coordinated such that supply and demand for electricity in the NEM are matched in real time (Han et al., 2020; Simshauser, 2019a). This ties the physical power supply with the supply and demand needs of the NEM in real time (Simshauser, 2019a). The NEM's forward markets signal the requirements for new capacity, with swap contracts signalling energy shortages and call options or 'caps' as they are referred to, signalling capacity shortages (Simshauser, 2019a)

Price spikes are common (and are a design feature) in wholesale electricity markets everywhere (Simshauser, 2019a). Price spikes also tend to increase with rising levels of VRE and Australia is no exception (McConnell et al., 2013; Simshauser, 2018). The NEM has experienced volatile spot prices (price spikes) due to a range of factors including power plant maintenance (both unplanned and planned), transmission maintenance (planned and unplanned), disorderly retirement of old generators, interconnector congestion, main transmission line congestion, market power abuse and more recently periods of low or no wind (Han et al., 2020; Nelson, 2018). Dealing with an intermittent generation capacity which does not always match the consumption pattern of consumers will continue to be a challenge for the NEM until feasible and cost-effective solutions are found.

Generation comes from the spot market (NEM in this case) however this means an unhedged generator is exposed to the price volatility within the spot market. Prices in the NEM can be as low as negative $1000 and as high as positive $16,600 (among the highest electricity market price caps in the world) (Simshauser, 2020). Generators having to pay these prices for failing to deliver fixed volume swap contract requirement for extended periods of time might face financial distress.

3.2 Financial market operation

Within the Australian NEM all electricity produced must be sold into the spot market in the first instance (Simshauser, 2019a). The forward derivates market supports the real time spot market at a wholesale level by providing futures contract prices (Worthington & Higgs, 2004). From there, 3 general options exist, (1) remove all price risk by selling the plant output under a PPA, (2) sell forward derivative contracts to hedge the price of electricity through futures, swaps or $300 caps, and (3) retain 100% exposure to the spot market (the latter being atypical) (Flottmann et al., 2022). Each option comes with different risks to the generator and seller of contracts. Under a PPA, the generator only gets paid when they generate and there is limited penalty for non-generation. The second alternative is the sale of electricity using derivative contracts. This is done by both traditional base-load generators and new VRE. Baseload generators can sell firmed swaps that guarantee the supply of electricity for VRE during periods of intermittency (Flottmann et al., 2022; Simshauser, 2020). VRE generators can sell swaps as a way of receiving fixed price electricity in exchange for providing green electricity to the purchaser. Under these derivatives the generator is exposed if they do not provide electricity and they have to pay the difference between the spot price and the contract price for each MW not produced (Simshauser, 2020). The option carrying the most risk is sale into the spot market when the generator is unhedged and fully exposed to price movements.

The derivative contracts in the NEM are traded both on-exchange and OTC with turnover historically at 300%+ of physical trade, with variations between season and regions (Simshauser, 2019a). The derivatives market in the NEM shows a classic commodity cycle path of mean reversion (Simshauser & Gilmore, 2022) highlighted by periods of high prices and periods of low prices (Figure 3). Coincidently these are also characterised by periods of generation buildout and contraction with the most recent being the ‘VRE supercycle’ see (Simshauser & Gilmore, 2020).

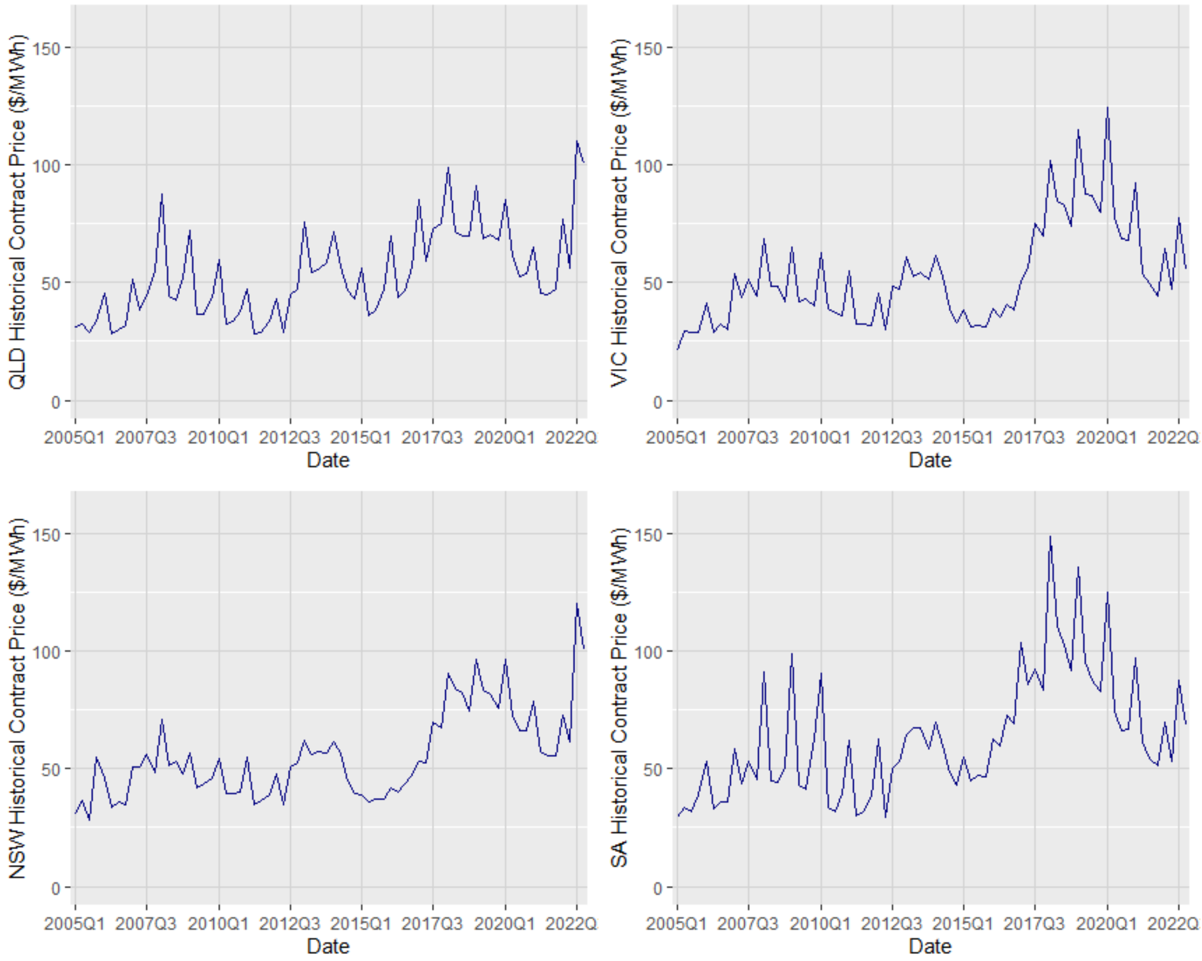

Figure 3 - Historical traded swap contract prices across the NEM from 2005-2022 for Queensland (top left), Victoria (top right), New South Wales (bottom left) and South Australia (bottom right).

Separate from the outcomes of spot market prices, the contract market can play an important role in the forward guidance of required plant build to support the NEM. As outlined by Anderson et al. (2007), the NEM contract market has comprised only a few contracting types.

- Bilateral OTC trades which are negotiated between two parties either a generator and retailer or developer and generator/retailer. In these trades counterparties negotiate the terms and structure of each contract. This type of trading is advantageous as parties can structure deals that match required hedging strategies. These trades can be based on swaps, options, PPAs, or other bespoke contract arrangements.

- Bilateral OTC trades executed through brokers on standardised products such as swaps and options. Once two parties are matched on price via the broker they discover who their trading party is. This process can be important for trading parties to learn who is a buyer or seller of particular contracts at a point in time. Brokers trading OTC products for NEM participants charge a commission for their service of matching parties to a trade.

- Exchange trading of standardised products such as swaps, caps and options with participants required to participate in daily settlement once a contract is agreed. Key benefits of exchange trading are that it's anonymous and credit risk is largely eliminated by the exchange requiring daily margin posting. Currently participants can trade products four years into the future on the Australian Stock Exchange (ASX).

Anderson et al. (2007) showed that market participants conducted a large volume of their trading through brokers. This is important in the NEM as brokers can bring different trading partners together as well as provide data and other specialist services. The groups active in the NEM contract market include, generators, retailers, intermediaries such as banks, speculators, and proprietary trading firms (Anderson et al., 2007).

There are several different derivatives available to market participants within the NEM and an almost infinite number of bespoke products to trade, provided one can find a counterparty. The standardised derivatives traded on the ASX are: swaps, $300 caps and options. Brokers and OTC markets will also trade all these standard contracts as well as bespoke derivatives which can vary in contract type, timing, shape and volume. A standard swap contract is an agreement between two parties to exchange the difference between a fixed price per megawatt hour (MWh) of electricity and a floating price which is referenced to the NEM spot price in the node traded (Qld, NSW, VIC & SA) (AFMA, 2019). A cap is an option which places a ceiling on the price a buyer will pay for electricity whilst the seller will compensate the buyer to the extent the spot price is greater than the strike price (on standard ASX caps the strike is $300). The various options traded are swaptions where the buyer has the right but not the obligation to buy an underlying swap on a future date at a predetermined price and Asian or average rate option where a payout is calculated referencing a specific period of averaging (AFMA, 2019). Additionally, a renewable energy certificate scheme known as Large Generation Certificates (LGC) is actively traded by participants in the NEM. LGC's are created by a VRE project producing 1 MWh of electricity generating 1 LGC. However, for the purposes of this research LGC's are not covered in detail as the focus is on derivates for energy and not green certificates.

In recent years governments have become the underwriter of derivatives through contracts for difference (CfDs) to increase investment in new generation mainly VRE. As explained by Simshauser and Tiernan (2018) when the Commonwealth Government commenced their review of the 20% renewable energy target (RET) it induced a cease of buy side PPA activity which, as explained in Section 6, are a common choice for financing new VRE projects. As a result government-initiated CfDs were implemented in the ACT, Queensland, South Australia and Victoria (Simshauser, 2019b). These CfDs were successful in meeting the policy objective of increasing renewable generation in each of the respective states, however, they can have unintended consequences on the derivative contract market. Increasing VRE can have a depressing effect on spot prices therefore lowering wholesale prices in the short to medium term (Simshauser, 2020). At scale, VRE plant is designed to replace coal plant and as it exits the forward market experiences rising shortages of "primary issuance" hedge contracts. This is in part because VRE plant has entered facilitated by CfDs rather than based on market transactions such as PPAs (Simshauser, 2019b). In an energy only market such as the NEM a poorly operating forward market can cause increasing risks for incumbent participants, increase contract premiums and force price-elastic customers to reduce spot market exposure and unintentionally cause the foreclosure of non-vertically integrated 2nd tier retailers (Simshauser, 2019b).

4. Survey of current market practices in the Australian NEM

4.1 Methodology

Here, the current practice of derivative contract trading and hedging by market participants within the NEM will be described. To understand how market participants trade in derivative markets and obtain their views on hedging practices an anonymous survey was conducted between January and March 2023 (Griffith University Ethics Approval 2022/889). The survey was sent to 35 market participants including all major generators, retailers and 'gentailers' as well as financial intermediaries, developers and brokers in the NEM. From this pool 21 responses were received (60% completion). However, as the survey was anonymous it was not possible to determine which participants of the total contacted responded. The total number of responses for each market participant type is listed in Table 3.

Table 3 - Total respondents to market survey

Market participant	Responses
Generator	7
Retailer	4
Gentailer	6
Financial intermediary	5
Developer	1

The participants contacted were in most cases the general manager of the trading team or a senior trader for their respective companies. As there was potential for commercially sensitive information to be disclosed the survey was kept anonymous and all questions asked were generalised so respondents did not give specific details of their trading activity. To provide respondents with the option to choose how much information they wanted to provide all questions had an 'other' option allowing for longer form answers and opinions. This longer form option provided additional insights on trading and hedging strategies as well as opinions on market operation. The survey questions were modelled using Anderson et al. (2007) and a full list of questions is provided in Appendix A. In summary, the themes the survey questions were designed to address were:

- Contract use within their business including types of contracts used, length held, proportions of contracts in portfolios and trading of contracts (exchange, broker or OTC).
- Modernised contracting structures such as the use of derivatives for solar, wind or shape contracts, changing exposure to spot pricing or modernised contracting structures and hedging altogether.
- Risks to their business or trading activity including general risks and questions on specific types of risk such as a lack of derivative liquidity. Additionally, participants were also asked to elaborate on whether they believed the market was functioning as it was designed to or if an updated structure was required.

4.2 Forward Derivatives use in the NEM

Derivative contract use within the NEM can occur for various reasons. However, ultimately it is used for reducing participants exposure to volatile spot prices or making speculative trades on spot price outcomes. Retailers are at particular risk of customer load flex on peak demand days which often coincide with high spot prices (i.e. compounding risk of high price *and* high quantity) and, as a result, use different types of derivative contracts to cover their portfolio. Generators (a natural energy long) sell volumes of derivatives to cover fixed costs whilst still allowing some exposure to spot pricing. Additionally, generators are exposed to risk once they sell derivatives and need to manage their portfolio to ensure they can meet their contracted supply. This is in case of unplanned outages or network issues during periods of high prices. The types of derivative contracts used by market participants varies depending on their company's strategy for trading and the types of exposure they already have to the market either through customers or physical generation. Of the question options available, survey respondents suggested flat swap, $300 cap, swaptions, PPA's and Asian options made up the largest portion of their portfolios (Figure 4). Some additional comments from respondents who selected the "other' option highlighted the use of OTC super peak contracts, tolling contracts, shaped swaps, and weather derivatives.

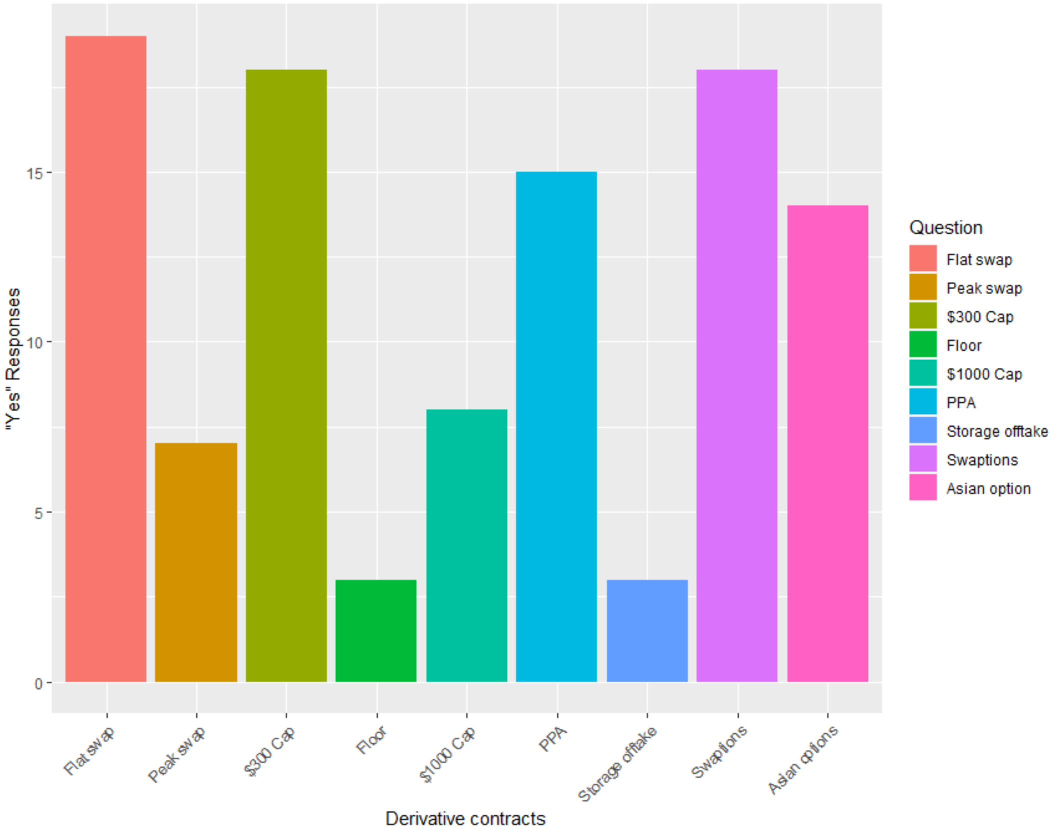

Figure 4 - Survey participants selection of derivatives which make up their portfolios.

This combination of contracts concurs with what is understood to currently make up most derivatives in the NEM. Figure 5 summarises this and provides a simplified example of how a combination of swaps, options and caps can be used to manage volumetric risk for a retail market participant. The central load profile (full black line) is achieved using a mix of baseload swaps, swaptions, shaped contracts and caps. Whilst the additional load flex (dotted red lines) is covered using weather derivatives such as temperature induced caps and cap contracts. Retailers preferred to use derivative contracts, closely matching their portfolio. Retail respondents suggested they used flat or baseload swaps, caps, swaptions and weather derivatives to manage their portfolios. While generators typically preferred to use derivatives which matched their generation profile (flat or peaking). As a result, shaped products are less common, and generators can charge a premium for selling those products to retailers. The average length of swap contracts held across respondents is reported to be 1-4 years.

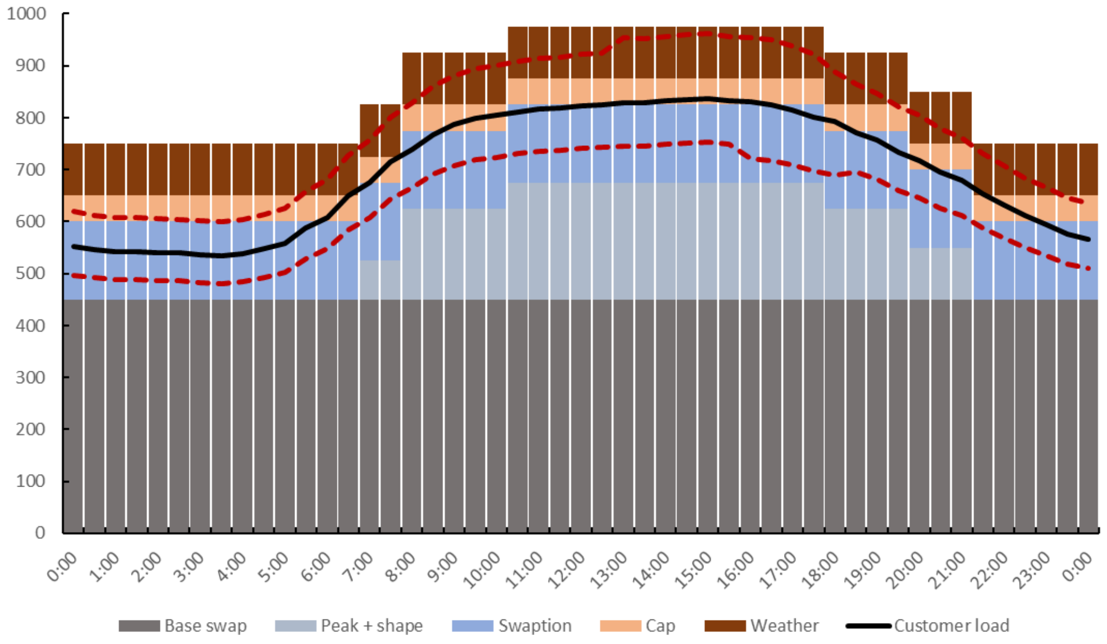

Figure 5 - Hypothetical hedging strategy for a retailer using flat swaps, peak swaps, options, caps and weather derivatives.

Survey respondents suggested that swap contracts made up a varying proportion of their portfolios. In the portfolios of those identifying as financial intermediaries' swap contracts comprised over 60% of the portfolios, whilst generators and gentailers generally held less than 60% of their portfolio in swap contracts (Figure 6). For gentailers this follows conventional wisdom of market participants as most gentailers use their physical generation as a hedge to be traded using derivative contracts (Boroumand & Zachmann, 2012). For generators holding less than 60% of swap contracts in a portfolio is different to conventional wisdom where it would be expected they hold at least 50% of their portfolio in swap derivative contracts. Potential reasons for this discrepancy are increased use of alternate derivates such as options or caps instead of swap contracts. Additionally, this survey was conducted during a period of very high spot market prices potentially encouraging more spot exposure over selling forward derivatives. In comparison, financial intermediaries mainly use derivative contracts to make speculative decisions on market outcomes which explains their higher use in portfolios as shown by the survey results.

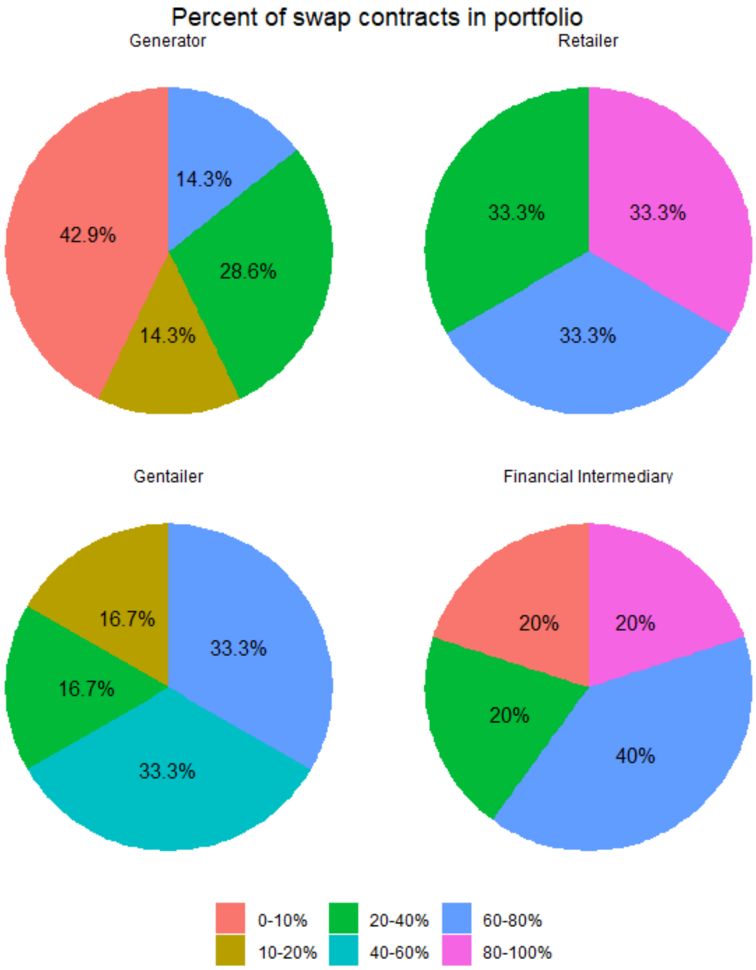

Figure 6 - Survey responses to percentage of swap contracts held in their portfolio each of the percentages represents the portion of respondents in that category who hold that level of swap contracts in their portfolio.

4.3 PPA and storage use by market participants

As more renewable energy has entered the NEM the simplest way to manage its entry and make financial close has been through PPAs for wind and solar developments (Gohdes et al., 2022). Typically, generators or developers will build and operate the asset and on-sell the energy from the asset through a PPA to retailers and large industrial customers. PPAs are being used increasingly as a mechanism for market participants to manage the risk associated with variable renewable plant and to satisfy the desires of customers wishing to decarbonise their electricity consumption. Due to PPAs longer contract timeline (typically 10 – 15 years) and bespoke contract terms they appear to not be widely traded among participants of the survey. Additionally, long dated PPAs are required to reach financial close for many VRE projects and as a result are unlikely to be traded between participants. Instead, they are reported to be often bought and held for the life of the PPA term. This reflects their relative difficulty to trade and the length of time they need to be held, therefore, they do not make up a large portion of most market participants portfolio's. Among participants contacted, there were a few specialty renewable generators and financial intermediaries who make up the outliers holding 80-100% of their portfolio in PPAs (Figure 7)[2].

[2] Caution may need to be exercised to the extent that the results indicate answers obtained from the respondents do not cover key concerns and choices of non-portfolio based VRE developers who depend on project financing to build their projects. A good representation of organisations on the purchase side was achieved but not necessarily on the sell side of PPAs of VRE projects.

As outlined above PPAs typically have a long contract duration, usually ranging between 10 – 15 years. However, of the market participants surveyed the length of PPA contracts differed markedly. Survey respondents who identified as retailers typically held PPAs for 1 – 7 years, with two thirds of respondents holding PPAs for 1-5 years (Figure 7). Interestingly, this length of PPA contract is unlikely to provide required financing for such capital intensive projects, contracts of 10-15 years are more generally required (Gohdes et al. (2022)). It is therefore theorised that the retailers with shorter dated PPA's are receiving them in one of two ways 1) they are the marginal quantity of VRE projects which have already sold the majority of their plant at 10-15 year contracts for financing. Or 2) the VRE project selling the PPA's is of older vintage with their first PPA's having ended, and these shorter PPAs are a second instalment of contract for the plant. Additionally, 1-5 years is consistent with the average length of a customer contract with a retailer or, commonly, within the liquid period of swap contracts traded on exchanges. Customers often do not opt for contracts lasting for extended periods at fixed price as this exposes them to the risk of capitalising on falling electricity prices. Shorter contracts (1-5 years) provide short-term certainty of costs for retail customers with longer term flexibility. The results of this survey show this practice is continuing between retailers and customers with more complex contracts such as PPAs.

In contrast, the survey results suggest that generators and gentailers are contracting renewable assets through PPAs for longer time horizons typically 7-15 years. This reflects the optionality of generators and gentailers to trade around VRE PPA contracts using their portfolio of dispatchable assets such as coal, gas and battery generators or on-selling the energy offtake of PPAs to customers. Given a large number of PPAs held by the big 3 gentailers in the NEM it is likely that they hold a significant portion of PPA volume indicating average lengths of PPAs held is at least 7+ years across the NEM. This result is consistent with the findings of Gohdes et al. (2022) that for project financing purposes PPAs need to ideally be 10-15 years in length.

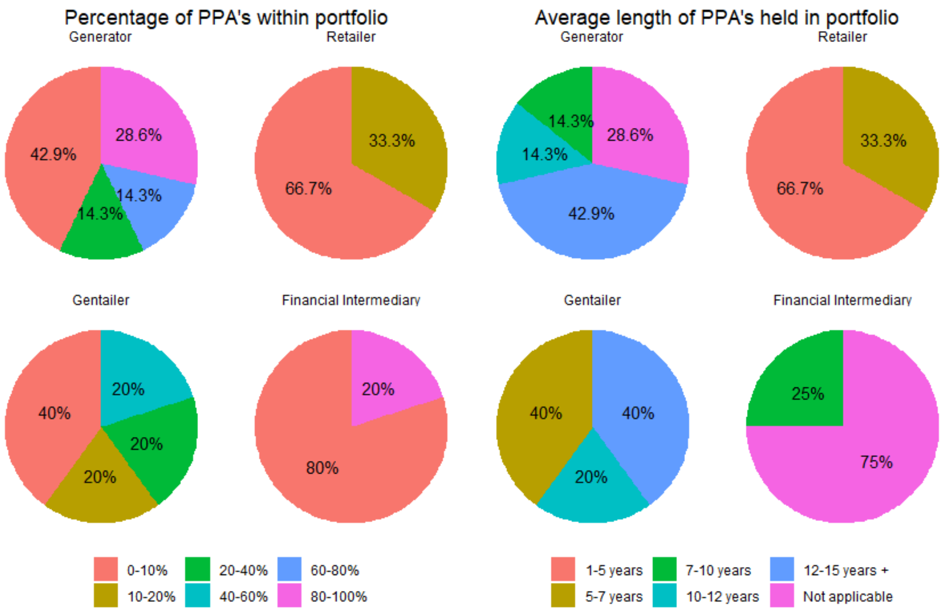

Figure 7 - PPA make up within participants portfolio's both percentage of PPAs in portfolio (right) and average length of PPA in portfolio at time of acquiring (left).

A set of survey questions was dedicated to the use of storage offtakes which are becoming an increasingly popular mechanism for market participants to gain use of a battery or pumped-hydro facility without owning the physical asset. Instead, the purchaser of a storage offtake or tolling contract could include dispatch rights, profit distribution from market activities or a heads and tails product which allows participants to buy at a certain price and sell at a higher price which mimics a storage device. However, due to their relatively new position, storage offtakes made up less than 10% of all participants portfolios. The few respondents who did have a storage-offtake reported having contracts lasting between 1-5 years and 7-10 years.

4.4 How did the participants contract?

Market participants appear to typically hedge using a combination of 3 different types of contracting. These methods occur using an exchange for standardised products, brokers for standard and some bespoke products and bilateral OTC trades for participant-to-participant trades.

The use of exchanges was mixed amongst respondents with financial intermediaries contracting 60%+ of their portfolio through an exchange whilst generators, retailers and gentailers appear to typically use exchanges for between 10 and 60% of their derivative volumes. However, across all participants the use of brokers for trading was higher than trading directly with the exchange. Brokers can provide traders with insight to the market without giving away confidential information about the participants they represent. Out of all market participants responding, the pure-play retailers used brokers the least for purchasing the required contracts.

Market participants can use OTC products in order to structure deals which adequately suit the need of a participant. These products make up 50%+ of the contracting of retailers and generators. This is consistent with market theory as generators can offer bespoke products to retailers who require these products to adequately shape their portfolio. These products typically provide generators a premium for contracting specific shaped products which may not necessarily perfectly suit their generation profile. Financial intermediaries contract the least using OTC methods which is unsurprising as bespoke deals such as these are not often traded between other parties and therefore do not suit their business model which requires liquidity in the products traded.

5. Market landscape and future landscape

The NEM has undergone significant change in the last decade since its founding in 1998. Additionally, it is an evolving market which is naturally different from the one surveyed in Anderson et al. (2007). The increase in the proportion of renewables and the resulting exit of dispatchable thermal plant has begun to have an impact on the derivatives contract market. Additionally, the decision by Commonwealth and State governments to become involved in the contract market for investing in VRE to meet their carbon emissions reduction targets is potentially having negative impacts on contracting ability.

5.1 Contract liquidity a growing issue?

The results of the survey indicate that hedging is a growing concern for market participants. 16 of 21 respondents communicated that this is an increasing issue to their portfolios. Concern for hedging positions comes as dispatchable coal plant (historically a dominant provider / supplier of hedge contracts) exits the market, taking their derivative contracts, which are used primarily as a hedging tool, with them. When most or all dispatchable plant has exited an electricity market it can be difficult to purchase derivative contracts OTC or through an exchange (Simshauser, 2019b). This is because if participants were able to purchase those contracts the buyer of the contract might pay a large premium as there are limited sellers. If a participant cannot get access to derivative contracts for hedging, they can become exposed to highly volatile spot prices.

The first case of a lack of contract liquidity has been observed in the South Australian (SA) part of the NEM. South Australia is the smallest mainland NEM state and historically highly vertically integrated, i.e. the associated derivative contracts are likely the first to become illiquid. The last major thermal plant to exit the market was the coal fired Northern Power Station, exiting in 2016, and has since been replaced by VRE, battery storage and peaking gas plant. The small amount of baseload dispatchable plant remaining is largely owned by ‘gentailers’ who utilise it to cover their own retail position. A lack of forward derivative contracts traded in South Australia on the ASX electricity derivatives exchange is often observed and, when contracts are traded, it is often at a higher premium compared with other NEM states (Figure 8). Furthermore, the volume of contracts traded and associated open interest are highly volatile in the SA region of the NEM, there are consistent quarters of no contracts traded over the exchange (Figure 10 & Figure 9).

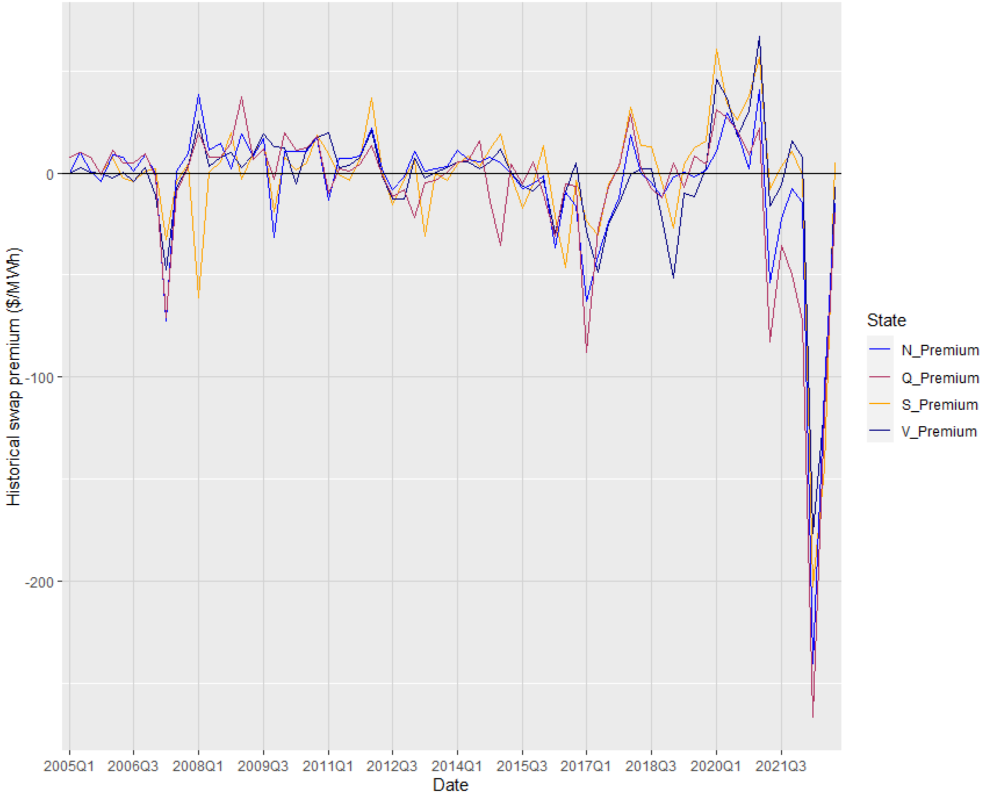

Figure 8 - Historical swap premium across all states. Where the premium is the difference between average contract price over the traded period and spot outcome for the period.

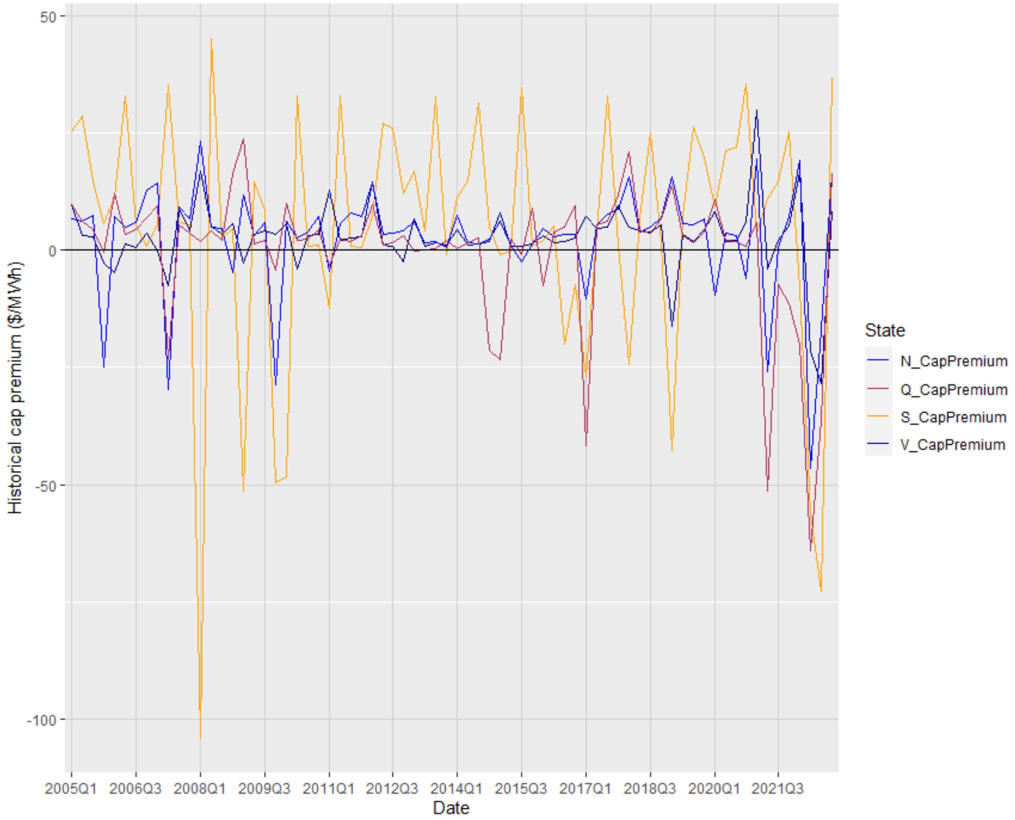

Figure 9 - Historical cap premium across all states. Where the premium is the difference between average contract price over the life of the traded period and spot cap outcome for the period.

The contract liquidity issue in SA has become acute with AEMO activating a policy known as the retailer reliability obligation (RRO). RRO is activated when AEMO identifies a lack of sufficient dispatchable plant available to meet peak demand during a certain period. At this point there is a requirement placed on retailers to purchase derivative contracts to ensure they are adequately hedged for this period of insufficient dispatchable generation. This policy was activated in 2022 for a period in Q1 2024 where there was deemed insufficient dispatchable plant in SA for peak periods. In a market where derivative contracts are already illiquid, such as SA, and there is a clear lack of dispatchable plant identified, it is likely retailers and ultimately consumers will pay a high premium for electricity during this RRO period. Importantly the policy does not ensure plant is made available or dispatched during this RRO period it only ensures retailers are financially hedged. As dispatchable plant exits the NEM in favour of VRE it is likely that RRO will be called again. Paradoxically it will become harder for retailers to meet their RRO requirements as derivative contracts sold by dispatchable plant will not be available for the hedge requirements expected as part of RRO.

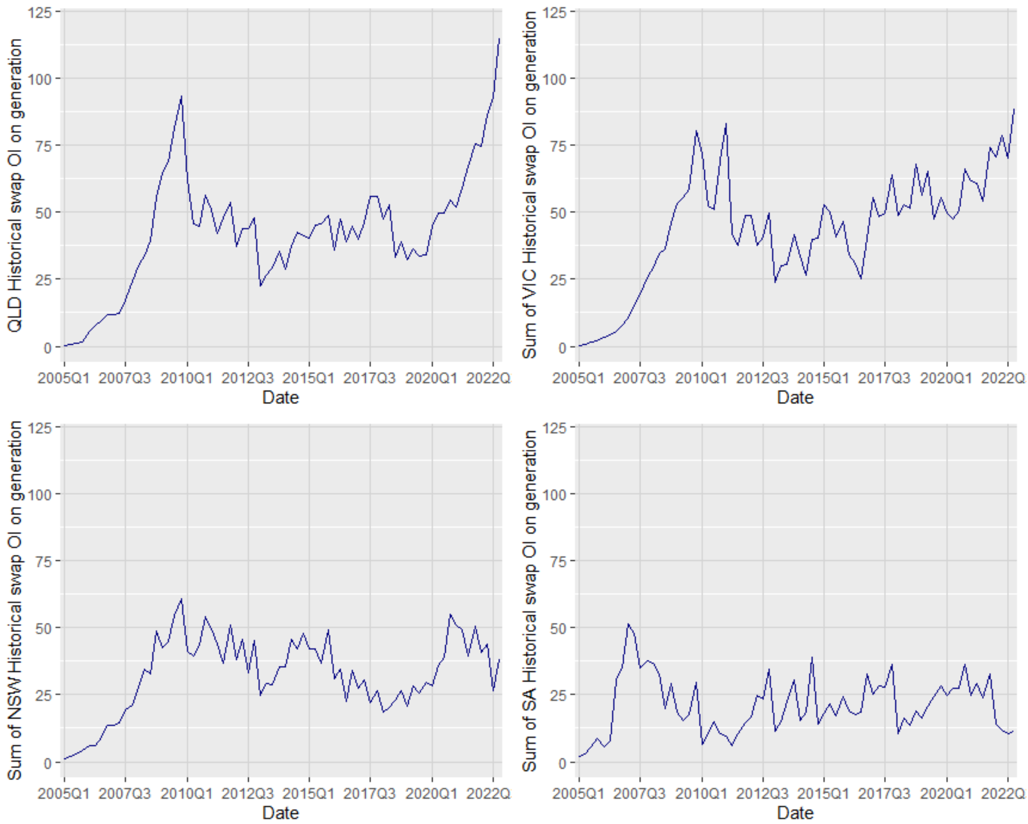

Figure 10 - Cumulative open interest in each NEM market from 2005-2022 divided by generation in GWh over the same period. SA (bottom left) has sharp movements in the contracts traded.

The reduced level of derivatives for the SA part of the NEM can be most likely attributed to two aspects. The first is SA is the smallest of the mainland NEM markets and as a result has historically never experienced the volume of contracts traded in other states where there is higher total generation (Figure 10). The second is that SA has become heavily vertically integrated in its retail and generation providers. As vertically integrated utilities can utilise their generation mix to hedge their retail portfolios there is little need to provide derivative contracts to the market. Hesamzadeh et al. (2020) showed how a large vertically integrated utility was able to exercise market power in SA both in the derivative market and spot market due to the limited competition and trade of derivatives in this region. The overall declining liquidity in the derivative market is concerning in the SA region since it can result in the exit of non-vertically integrated 2nd tier retailers as described by Simshauser (2019b). Vertical integration's impact on the swap market was a concern of all retail respondents to the survey as all answered with an interest in growing their generation presence in regions of high vertical integration. All generators and gentailers who participated in the survey appear to also consider expanding or acquiring exposure to markets with high levels of vertical integration. This dash for physical plant in regions of already high vertical integration is of concern as it could mean the demise of non-vertically integrated retailers.

One area that is impacting the entire NEM is the volume of traded peak swap contracts has fallen to historically low levels across all states within the NEM due to its relative "outdatedness". As shown in Figure 11, the volume of peak contracts across all states has fallen to some of the lowest levels observed historically. The fall in the volume of these contracts appears to begin in 2014/15 across NSW, QLD and VIC. This timing aligns with the increase of rooftop and utility-scale solar PV in Australia which reduces household demand and in turn spot price outcomes during daylight hours.

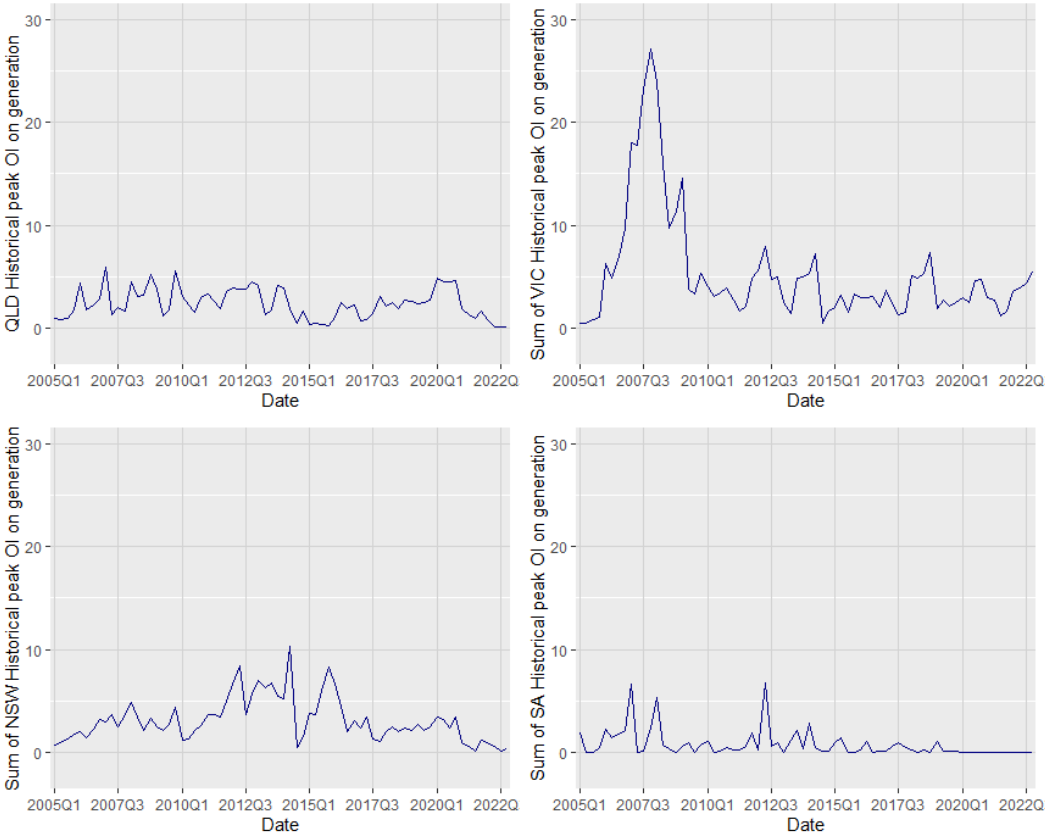

Figure 11 - Historical peak swap volume traded within the NEM divided by generation. For nearly all states the volume of peak contracts begins to decline between 2015-2017 coinciding with a reduction in peak time demand as rooftop PV systems are installed.

The traditional peak period contract offered on the ASX is from 7am – 10pm Monday to Friday (excluding public holidays and other days determined by the ASX). Traditionally this period was when retail customers increased their electricity usage and therefore the average spot price increased. This created demand for a specific shape product during these peak hours. However, this time period now includes a significant portion of solar hours where the price is considerably lower than traditional off-peak hours. Whilst the early evening often related to a spike in prices due to the reduction in solar, increased domestic consumption and the consequent ramping required from coal and gas generation. This makes a traditional peak contract difficult to value and traditional sellers of peak swaps (coal and gas generators) have reduced their volumes offered to the market. Whilst traditional buyers of peak contracts (retailers) do not need them as solar hours are relatively cheaper than the flat tariff they offer customers and the early evening can be partially hedged using $300 cap contracts.

Without a liquid contract market hedging becomes increasingly difficult for many market participants. The example of peak swap contracts is the reduction in need as electricity consumption has been offset by rooftop PV resulting in a loss of peak contracts within the market. 80% of the surveyed market participants confirmed a lack of swap contracts was impacting on their forward contracting needs. One way of resolving swap contract liquidity for nearly all generators, retailers or gentailers is to increase exposure to the physical markets (e.g. purchase of dispatchable plant or VRE) which all said they are actively looking towards.

5.2 Modernised contracts

To navigate and update some of the outdated derivative contracts on offer through exchanges such as the peak swap contract the market has created bespoke contracts. These contracts commonly trade OTC to help shape requirements for hedging generation or retail positions. However, at this time most of these contracts are bespoke and therefore not easily traded or exchanged between parties once the initial trade has occurred.

There are several different types of OTC renewable and shape contracts available to market participants. The most common are a ‘super peak’ swap contract, solar shape and solar firming option. The ‘super peak’ swap contract is gaining momentum as an alternative to a traditional peak contract. This contract is often traded for the hours 4pm – 9pm where demand begins to increase (and ultimately peak) as consumers arrive home from work to use electricity at the same time as rooftop solar systems reduce their output due to sunset. Whilst the solar shape contract enables a purchaser to buy all the half hours and associated LGCs for solar hours (typically 8:30 – 5:30). In a solar firming contract the buyer will purchase all the half hours outside solar hours to value the firming required from a flat swap around solar. Standardised solar shape and solar firming contracts which can be traded through a renewable broker (Core Markets).

Survey participants were asked for their preference for renewable (wind or solar) shaped contracts or ‘super peak’ (evening peak or morning peak) shaped contracts. Of the gentailers and retailers, 100% confirmed they were interested in ‘super peak’ style contracts. Whilst generators and financial intermediaries preferred wind and super peak contracts and only one preferenced solar shaped contracts. Bespoke ‘super peak’ or shaped contracts can be traded between parties on an ad-hoc basis there is no standardised contract traded through a broker or exchange. One Australian gentailer had workings of a tradeable wind contract however as of yet there is no standardised wind contracts which can be traded (Parkinson, 2018). Despite renewable and shape contracts largely being nonstandard, 95% of the respondents said they are currently using a form of shape contract or are interested in using shape contracts.

A final option as an alternative to hedging is increasing exposure to spot prices which is highly risky due to the volatile nature of an energy-only wholesale spot market. Increasing exposure to spot prices would most likely be done during the middle of the day where the average spot price is lowest and price spikes are uncommon. However, as we transition to an increasingly VRE dominated generation mix price spikes increase due to cloud cover over solar farms or large cities with high concentrations of rooftop PV. Of the market participants generators and retailers were far more willing to take increased spot market exposure whilst gentailers were not willing to take increased spot exposure. Of those willing to increase their spot exposure 100% of retailers were willing to increase exposure to 10-15% whilst generators were willing to increase exposure to 15%+. Generators and retailers have the most to gain and lose from increased spot exposure whilst gentailers have typically invested in physical assets to cover their retail position instead of swap contracts and as such do not need increased spot exposure.

Currently the use of renewable or shape-based contracts is commonly occurring alongside the current suite of swap and option contracts available to market participants. A portfolio of swap, option and bespoke shaped contracts may look like the conceptualisation in Figure 12. In this case a mixture of solar, super peak and spot exposure is used to form hedge coverage. Note that the spot exposure occurs during the solar hours (9am – 3pm) where spot prices are typically lowest and solar exposure is highest (Figure 12).

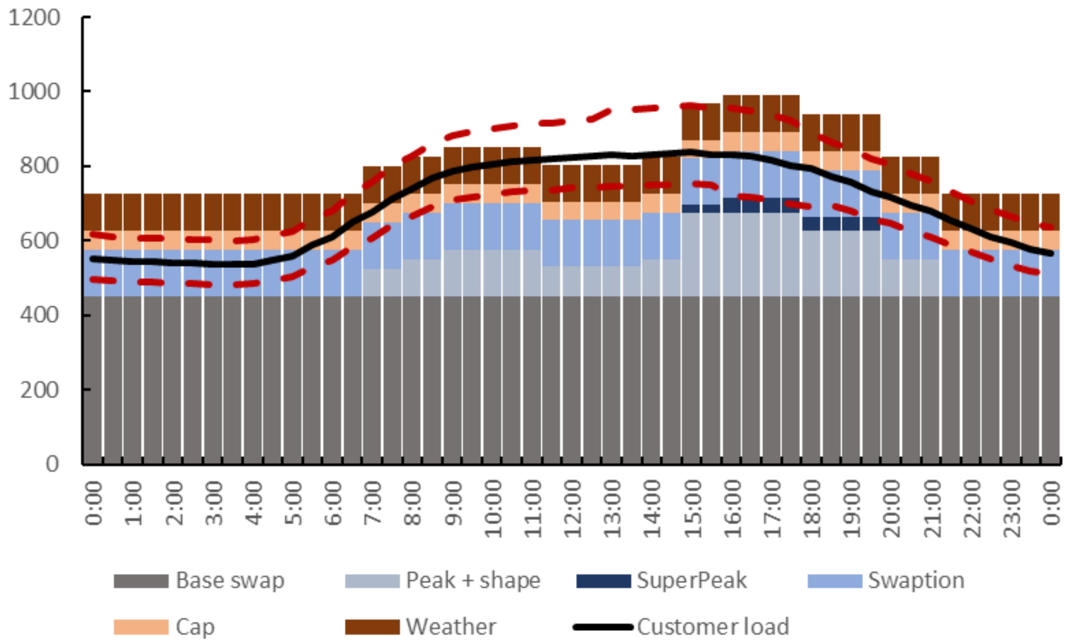

Figure 12 - Hypothetical hedging strategy involving swaps, options, caps, weather derivatives, bespoke shape, and spot exposure.

As the NEM changes its generation mix and withdraws capacity in dispatchable plant the current suite of derivative contracts may be unsuitable to maintain an active contract market. In that case renewable and/or shape contracts could theoretically replace the use of traditional baseload swap contracts. The results of this survey suggested retailers believed they could replace their current hedging model with renewable and shape contracts. Whilst the majority of generators, gentailers and financial intermediaries believed shape contracts were better suited as an added option additional to the swap contracts already available to the market. These results are unsurprising as traditional generators and gentailers still own all the remaining dispatchable plant in the NEM and therefore do not require shape contracts to hedge their portfolios. Retailers appear to be the market group potentially suffering the most from contract illiquidity issues associated with the removal of dispatchable plant. Therefore, retailers can utilise both renewable and shape contracts to actively hedge their portfolios and potentially improve retail tariffs for consumers.

5.3 Is the forward contract market operating as intended?

The NEM contract market is relatively liquid in the three main eastern states (QLD, NSW and VIC) with average aggregate derivative turnover across the NEM currently in excess of 500% on generation. However, the closure of most dispatchable plant in SA has left that contract market illiquid and increasingly untraded. Additionally, as explained in Section 5.1, the trade of peak contracts has fallen to historic lows due to its limited usefulness in the current NEM environment. This indicates there are potentially future issues for the NEM derivative market if not addressed prior to the exit of dispatchable thermal plant.

The availability of derivative contracts traded has not been improved by State Governments offering off-market transactions of CfDs between generator and government replacing the traditional on-market transaction of contracts between generator and retailers. As explained by Simshauser (2019b) this can have serious impact on the stability of an energy only market as dispatchable thermal plant is replaced with VRE funded through government initiated off-market CfDs. Eventually there will be a shortage of primary issuance hedge contracts. Shortages such as these ultimately result in the exit of 2nd tier non-vertically integrated utilities as they cannot gain access to hedge contracts. Australian State Governments have continued using CfDs and other derivatives as the primary mechanism to procure VRE. An ongoing issue is how to construct this structure after accounting for the possible requirements of long term PPAs to fund the building of VRE projects. If this remains the case into the future, a lot of the instruments might need to be, in the first instant, PPA's that currently are not widely traded. The issuance hedges on the other hand are based around 1-4 year products that are used for risk management purposes once projects are operational. This gap is potentially bridged by the purchasers of PPA's instead of the sellers.

The latest government backed scheme is the NSW Governments Long-Term Energy Service Agreement (LTESA). Which acts as a put option contract and is intended not to disrupt the forward markets per se (as the put is an option). When holders of an LTESA exercise their option and they then receive a fixed floor payment for their generation from the NSW Government. A ceiling price triggers a clawback where the NSW Government takes up to 75% of revenues above the designated ceiling price until payments are repaid. LTESAs are offered as part of a competitive auction and the winners receive a 20-year contract which can be exercised at 6-month intervals for the forward 2 years. Importantly, these contracts are not only for VRE but also long duration storage. Long duration storage LTESA's are designed to replace the aging dispatchable thermal plant and provide firming for increasing volumes of VRE.

Aside from a loss of hedge contracts the derivatives market provides additional benefits to volatile energy only markets such as the NEM. Forward contracts are the means by which the market provides a level of guidance on the requirement for new entrant plant i.e. when swaps are consistently elevated it indicates new energy producing plant is required and encourages their entry through higher contract prices. Whilst rising cap prices indicate new peaking capacity is required. Without market mechanisms encouraging the entry of new capacity it would be left to government. One only needs to look at reasons for the NEM liberalisation to understand how government run electricity utilities had an oversupply of generation, low levels of plant availability and investment risks were borne by the consumer. If governments continue to procure new VRE and storage through government initiated CfDs the market mechanisms required to operate an energy only market such as the NEM may disappear.

Currently, two thirds of survey respondents consider the NEM contract market provides forward guidance on generation requirements however they note it can be difficult to determine what indicators are being provided. Overall, 10% of respondents believed the market is completely disconnected at providing any guidance on future generation requirements while 20% believe it is operating as designed.

Of the market participants surveyed, 95% confirmed that innovation in the contract products offered to participants is required. If the NEM is to have an active derivative contracting market into the future it will require some form of product innovation or overhaul of the market traded. Without any form of innovation or overhaul it is likely to become increasingly difficult for retailers to hedge their market positions in an efficient or economical way.

6. Conclusion and policy implications

The NEM is undergoing a significant change as part of the Commonwealth Government's commitment to reduce carbon emissions. The exit of aging dispatchable thermal plant and entry of VRE has potentially begun to have an impact on the forward derivatives market. The forward market has traditionally been very liquid with average derivative turnover 300-500% of generation. However, there is now a reduction in the offering of peak swap contracts – this contract has clearly dated given the fundamental change in the plant mix vis-à-vis solar generation (both utility scale and rooftop PV). This provides a problem for policy makers and regulators as without a well-functioning derivative market an energy only market such as the NEM can break down. There are solutions to this issue through implementation of modernised contract structures to reflect an increasing VRE dominated market.

Governments and policy makers should consider the wider market conditions prior to implementation of policies such as the RRO. There is a requirement for retailers to purchase financial contracts for hedging and these are primarily sold by the very plant exiting the market ultimately resulting in higher prices for retailers and consumers. In areas of high vertical integration such as SA there is little incentive from those remaining dispatchable plant operators to sell forward derivatives during an RRO period as they require the plant as cover for their own retail customers.

The results of the survey show hedging is a serious concern for most market participants. Swap contract availability is pushing some participants to increase their physical asset presence in areas where vertical integration is potentially impacting the liquidity of swap contracts. Additionally, generators and retailers are increasingly willing to expose a portion of their portfolios to volatile spot prices in the absence of derivative contracts. The results also indicate that market participants are open to innovation in their willingness to use renewable and shaped contracts to form whole or part of their hedge contract cover. Participants are increasingly using, and open to using, PPAs and storage offtakes as a method of getting physical asset exposure without being involved in development.

Participants believed the contract market is still largely operating as designed in providing forward guidance and hedge cover to those who require it. However, it was noted that some participants feel the derivative market is at times opaque. Nearly all participants surveyed believe the contract market requires innovation. Without innovation in the types of standard derivative products offered to the market it may be difficult for VRE and storage projects to gain financing outside PPAs or government backed CfDs.

If State and Commonwealth Governments continue to use off-market CfDs and other derivative contracts as their main method for procuring VRE the derivative market could rapidly lose liquidity. To ensure the market does not lose non-vertically integrated 2nd tier retailers' policy makers should look to create contract structures that can form part of an active derivative market. Whilst also ensuring they meet the requirements of VRE projects to secure project financing for construction as historically this has been done with long dated PPAs which have not been widely traded as this survey indicates. Without such well-developed contracting an adequate derivative market may become illiquid and untradable.

Finally, to support an active derivative market in a future of high VRE exchanges such as the ASX should modernise the contract products offered to participants. The simplest option is to change the current peak contract to be more aligned with the OTC traded super peak contract (4pm – 9pm instead of 7am – 10pm). Whilst the creation of a wind CfD which many participants are interested in could help both generators and retailers continue to adequately hedge their portfolios. As dispatchable plant exits the market these modern and updated contracts could theoretically makeup the primary issuance hedge contracts used in the market. If these contracts were to be created an issue remains whether VRE projects can gain financing without the use of PPAs as has been the preferred mechanism to date. Further studies are needed to determine if a mixture of VRE based contracts and peaking contracts could sustain an active derivative market.

7. Appendix A: Survey Questions

Part 1 - Introduction

1. Please select the type of company you believe best describes your business.

Generator
Retailer
Gentailer
Broker
Financial Intermediary
Developer
Financer
Consultant

2. What is the greatest risk currently confronting your business or you see confronting businesses within the National Electricity Market?

Insufficient dispatchable generation
Exposure to international commodity prices
Energy transition speed
Grid connection &/or transmission issues
Policy discontinuity
Cost of developing new generation
Maintaining market share/customer base
Hedging market position
Other*

Part 2 – Current hedging practice: the following questions will focus on current forward contracting use within your business and their use.

3. What types of derivative contracts are currently used in your business?

Flat Swap
Peak Swap
$300 Cap
Floor
$1000 Cap
PPA
Storage offtakes
Swaptions
Asian Options
Other*

4. What portion by MWh volume do flat swap contracts typically make up your portfolio or traded positions (estimate)?

0-10%
10-20%
20-40%
40-60%
60-80%
80-100%

5. What is the average length of swap contract at time of purchase held in your portfolio?

3 months
6 months
9 months
1 year
1.5 years
2 years
2.5 years
3 years
3.5 years
4+ years

6. What portion by MWh volume do variable renewable Power Purchase Agreements (PPA's) make up of your portfolio or traded positions (estimate)?

0-10%
10-20%
20-40%
40-60%
60-80%
80-100%

7. What is the average length of PPA's at contract inception held in your portfolio?

1-5 years
5-7 years

7-10 years
10-12 years
12-15 years +

8. What portion by MWh volume of storage offtake contracts (battery or PHES) make up your portfolio or traded positions (estimate)?

0-10%
10-20%
20-40%
40-60%
60-80%
80-100%

9. What is the average length of storage offtake contracts at contract inception held in your portfolio or alternatively do you already own battery energy storage system (BESS)?

1-5 years
5-7 years
7-10 years
10-12 years
12-15 years +
Own battery BESS

10. What portion of your derivative contracts are traded through an exchange (e.g. ASX/FEX)?

0-10%
10-20%
20-40%
40-60%
60-80%
80-100%

11. What portion of your derivative contracting is traded through a broker?

0-10%
10-20%
20-40%
40-60%
60-80%
80-100%

12. What portion of your derivative contracting is traded over the counter or with a direct counterparty (e.g. generator to retailer direct)?

0-10%
10-20%
20-40%
40-60%
60-80%
80-100%

Part 3 – Hedging in the future: current market risks and potential future market risks

13. What potential risks do you see for your business if there was a lack of swap contract availability in the market?

Inability to hedge retail load
Revenue loss
Unable to meet minimum risk management for generator hedging requirements
Inability to gain finance for new projects
Over-exposure to spot prices and risk of price spike exposure
No potential risks to current business operations
Other*

14. What impact do you see vertical integration currently having on the swap contract market? E.g. South Australia's limited swap contract tradability?

No impact on current forward contracting needs
Low impact on current forward contracting needs
Increasing impact on current forward contracting needs
Severely impacting current needs and access to forward contracts
Other*

Additional Information**

15. How does your company view potentially increasing the level of vertical integration (e.g. purchasing of renewable assets &/or peaking plants such as batteries or gas turbines or increasing retail business) as a hedge for reducing swap contracts?

Not currently looking at increasing physical asset presence in any region
Potentially looking to increase exposure to physical markets for hedging but nothing certain right now

Currently looking for physical presence in markets or alternative methods in locations where vertical integration makes forward contract access difficult
Other*

Additional Information**

16. Currently what is your preference for renewable or alternative shape-based contracts to buy/sell or trade in for hedging your portfolio?

Solar
Wind
Super peak (early morning and early evening/ before and after solar hours)
Overnight

17. In the context of your business, what is the current appetite for renewable shape based (solar & wind) contracts?

Not interested, don't see their use
Very interested
Our business model isn't suitable for shape based contracts but regards them as useful
Will potentially use them in the future but not at the moment
Other*

Additional Information**

18. Does your business see shape contracts as additional to current swap contract cover or could they be used to replace swap contract use in your business?

Yes, we see shape based contracts as an added option for hedging alongside swap contracts within our portfolio.
No, we do not believe shape contracts can be used along side swap contracts within our portfolio
We believe shape contracts can completely replace the use of current swap contracts within our business model
We believe shape contracts can replace our current use of swap contracts within our business model however, they may require additional products for support such as weather derivatives Asian options or some other products.
Other*

If you would like to provide additional insight into how you may use shape contracts within your business please answer below.**

19. In the case of a loss of swap contracts in the market, would a change in your company's spot risk exposure be accepted?

Yes
No

If yes, to what degree might you increase spot exposure as a part of your business model?

0-5%
5-10%
10-15%
15-20%
20%+

20. Based on the response options below to guide your answer, do you believe the current forward contracting market is doing an adequate job of forward guidance on the need for dispatchable generation in an increasingly renewable based energy system?

Yes, it provides adequate forward guidance on generation requirements in NEM regions
No, the forward market is disconnected from future generation requirements and intervention is required
It provides some forward guidance on new generation requirements but can be difficult to determine
Other*

Additional Information**

21. Based on your answer to the above and using below response options indicate the following: Do you believe the current suite of products offered for forward contracting is adequate for hedging under a National Electricity Market which is increasing in renewable generation and reducing dependance on dispatchable generation?

Yes, the current suite of products is adequate
No, the current suite of products is not adequate and requires a review
The current products available provide some hedging coverage but more innovation is needed as we move towards increasing VRE exposure
Other*

Additional Information**

8. References

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