ElectraNet

SA-NSW Interconnection – Analysis of Impacts on Liquidity in SA

February 2019

CQ Partners

Contents

1 Executive Summary

- *Market liquidity continues to decline in SA and generally across the NEM as conventional plant retires as they reach end of economic life. AEMO projects coal fired generation to reduce to nearly half of the current installed capacity by 2035 and around 20,000MW of capacity to be retired by 2050.*
- *Conventional generators have traditionally been the suppliers of futures contracts (hedging contracts) in the market as this technology type is able to generate as needed to meet its contractual obligations. As conventional generation (both coal and gas) plants retire, there is reduced supply of hedging contracts and as a result the market will need to adapt to alternative mechanisms to manage risk.*
- *The ability to manage spot price risk has deteriorated in SA over the past few years as hedging contract liquidity has reduced due to the retirement of conventional dispatchable generation plant (namely Playford and Northern Power Stations) and inconsistent utilisation of Pelican Point Power Station over several years (noting that the plant has run to near capacity in the second half of 2017 and 2018).*
- *The expected withdrawal of the Torrens Island A Power Station (480MW) from 2019 will further reduce hedging liquidity. Uncertainty on the longer-term role in the market of gas baseload plant in SA will see 1,462MW retire from 2024/25 according to AEMO's ISP post the new interconnector.*
- *Market concentration is also a factor in the level of contract liquidity, as the three major 'gentailers' (AGL, Origin and Engie) own the majority of the GPG fleet in South Australia, making it difficult for other retailers to compete in a spot market that has historically had price volatility.*
- *The lack of forward hedge contracts has limited the ability for new retailers to compete in SA and as a result the cost impacts to customers, particularly large industrials have been material.*
- *It is considered likely that GPG plant, particularly those that are inefficient (have high heat rates), will not be competitive in the medium to long term as compared to low cost renewable generation, largely due to the high cost of natural gas. Consequently, it is likely that these less efficient plant will also exit the market regardless of whether interconnection occurs or not.*
- *It is likely that the impacts on contract liquidity (i.e. the deterioration of liquidity) will occur as a natural consequence of conventional plant retirements as they reach the end of their economic life or when they become uncompetitive due to high fuel costs. This is not just a SA dilemma, but a national one. It is difficult to predict the impacts of an interconnector between NSW and SA on contract liquidity as this has not been modelled, however intuitively, the interconnector will aid the sharing of generation resources across regions and will increase the benefit of electricity flows between regions from lower cost renewable generation facilities.*
- *In the medium to longer term, a new interconnector can be expected to have a number of positive impacts on market liquidity in SA. This should occur as participants utilise inter regional hedging to a greater extent, particularly as greater storage capacity is built across the NEM (as forecast to occur by AEMO).*
- *The presence of increased interconnection between SA and NSW is likely to encourage investment in grid-scale storage projects providing hedging options in SA as well as introducing lower delivered electricity to the market.*
- *It is expected that the market will utilise utility scale storage and embedded distributed storage in a way that effectively provides a physical hedge to spot price volatility. The ability to utilise utility scale storage and embedded storage more effectively than say a $300/MWh cap, is likely to add greater price certainty to customers (particularly those exposed to the spot price) and also reduce the overall cost of electricity to customers over the longer-term. The assumption here of course is that investment in large scale storage, embedded generation and large-scale renewable generation will occur in line with the retirement of conventional generation.*
- *The ability to utilise both the Heywood Interconnector and a SA - NSW Interconnector for inter-regional hedging utilising settlement residue auction units and local utility scale storage plus peaking GPG is expected to assist in the ability of parties to manage spot price risk.*
- *We also note that the ability of regions to hedge inter-regionally will also be important and the SA - NSW and Heywood Interconnector will increasingly be important to facilitate the flow of lower cost*

electricity into other regions but will also assist participants to hedge risk as traditional sources of hedges exit the market. The utilisation of the Heywood Interconnector has provided SA customers and retailers with an alternative to just SA based hedges, creating better liquidity. Additional interconnection should increase liquidity through further inter-regional hedging.

- *Interconnection of markets will assist in the sharing of renewable resources across regions, which should aid in the reduction of spot price volatility and prices. As spot price volatility reduces, participants will have less pressure to manage price risk through hedging instruments.*
- *In summary, the NEM is moving away from conventional generation (particularly coal fired generation) as they reach end of economic life. As this occurs, the market will look to transition to new forms of price risk mitigation. The utilisation of large-scale storage, embedded generation and increased interconnection between regions will be invaluable to market participants in this transition.*

ElectraNet is in the process of undertaking a public consultation process covering the proposed 800MW Robertstown to Wagga interconnector, which has been identified as the preferred option (referred to as "Option C3") in its South Australian Energy Transformation (SAET) Project Assessment Conclusions Report (PACR) following the Preliminary Assessment Draft Report (PADR) released in mid-2018.

The focus of this paper is to provide a qualitative assessment of the potential impacts to hedging liquidity within the SA region, as a result of the SA to NSW interconnector (as per Option C3) being implemented. This report is not intended to provide modelling forecasts of spot or forward contract pricing, nor is it intended to review or critique the Option C3 or the analysis that has been undertaken to date by ElectraNet and AEMO. This report is purely an assessment of the current and expected future hedging market in SA, particularly in light of the proposed NSW – SA Interconnector.

ElectraNet received submissions related to the SAET PADR and has considered these in addition to modelling from the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP). The ISP forecasts that over a 20-year period, there will be a substantial retirement of conventional generation as they reach end of plant life. The modelled impact is that about 70,000GWh of electricity generation will be retired from the NEM and by and large will be replaced by renewable generation and storage and a small amount of flexible gas-powered generation (GPG).

The National Electricity Market (NEM) was designed as a gross pool energy only market, which ordinarily relies on high and volatile spot prices to encourage new investment in generation facilities. The ability to manage the risk of material spot price volatility has necessitated the ability for counterparties to hedge their price risk in the market. Hedging is undertaken outside of the normal NEM settlements process, either undertaken over the counter (OTC) between parties or via the ASX as an exchange traded forward contract. In either case, the settlement of the hedge is done outside of the AEMO market settlement process. The alternative to the OTC or ASX forward hedges is to have physical generation that acts as a natural physical hedge or for large consumers, the ability to demand side manage can also act as a form of physical hedge, albeit at the cost of production.

Market liquidity continues to decline in South Australia

The SA electricity market is characterised by high cost gas plant[1], significant renewable generation, 130MW of grid scale battery storage and interconnection with Victoria. The ability to manage spot price risk has deteriorated in SA over the past few years as hedging contract liquidity has reduced due to the retirement of conventional dispatchable generation plant (namely Playford and Northern Power Stations). This is not expected to improve in the short to medium term. The lack of hedging liquidity has made it difficult for incumbent and new entrant retailers and market facing customers to manage spot price volatility.

The following table illustrates that SA will have about 800MW of GPG, with a further 210MW committed with Barker Inlet and a further 660MW of CCGT plant. This in addition to the Heywood Interconnector effectively provides the supply of swaps in SA. This is effectively just enough to manage the risk of SA's average demand of about 1,300MW, with the OCGT and battery storage catering for peak demand requirements.

The issue that SA has however is that the three major 'gentailers' (AGL, Origin and Engie) own the majority of the GPG fleet. This allows them to effectively manage their own vertically integrated position, but makes it difficult for other retailers and new entrant retailers to compete in a volatile spot market.

Figure 1 SA – Existing, Committed and Proposed Generation Plant

Status	Coal	CCGT	OCGT	Gas other	Solar*	Wind	Water*	Biomass	Battery Storage	Other	Total
Existing	-	663	1,198	1,280	122	1,809	4	20	130	145	5,371
Announced Withdrawal	-	-	-	480	-	-	-	-	-	-	480
Existing less Announced Withdrawal	-	663	1,198	800	122	1,809	4	20	130	145	4,891
Committed	-	-	-	210	218	251	-	-	-	-	679
Proposed	-	45	624	-	2,388	3,330	755	15	488	30	7,674
Withdrawn	-	-	-	-	-	-	-	-	-	-	-

Note: Existing includes Announced Withdrawal

* Solar excludes rooftop PV installations

Source: AEMO – Website 2 November 2018 Generation Information

The issue for SA and for the NEM more broadly is that as renewable and utility scale storage continues to displace GPG and as coal fired generation retires, there will be reduced contract liquidity that would allow buyers of electricity to manage price risk.

There are benefits and drawbacks to this trend. On the one hand, emitting generators are being replaced by low emitting renewable generators and also those that have a significantly lower running cost. However, this brings with it the challenge from a financial hedging and risk management perspective that the market now has to consider alternative forms of risk mitigation than the forward contract structures it has been used to.

The primary sellers of hedges in the NEM have been conventional generation facilities that are able to generate electricity to be delivered into the NEM to offset the hedges that they sell. The primary buyers of hedges are retailers and market customers that have exposures to the spot price when consuming electricity from the NEM. It is important for retailers in particular to manage price risk, as they usually sell fixed priced contracts and purchase electricity from the NEM on a floating price basis. The problem to date has been that the renewable generation fleet of wind and solar generation that has been replacing conventional generation does not always provide energy on demand and as a result these operators are not natural sellers of hedging contracts. This is where utility scale storage and sharing of generation resources across regions can make a difference. The

[1] The cost of natural gas is now linked to LNG international netback price. Contractual gas prices have gone from about $5/GJ about 3-4 years ago to around $10/GJ + in recent times. This has significantly increased the short run marginal cost of GFG plant across the NEM.

lack of forward hedge contracts has limited the ability for new retailers to compete in SA and as a result the cost impacts to customers, particularly large industrials have been material.

Known developments likely to impact on contract liquidity going forward include:

- Both AEMO and ElectraNet show that TIPS A (480MW) will retire in the near term (2019-21) and 1,462MW of baseload gas plant are also forecast by AEMO in its ISP to retire around 2024/25 with the new interconnector. The Barker Inlet GPG (210MW) that is due for commissioning during 2019 will somewhat offset the loss of TIPS A. The new reciprocating engines are fast start and will be much more efficient than the existing generator and much more capable of responding to future 5 Minute market spot prices. From a contracting perspective, we would expect some reduction in the availability of swaps as a result of this retirement, even with Barker Inlet coming on line. However, this in itself is not material.

- Future generation entry including Bungala Two Solar Farm (110MW), Tailem Bend Solar Farm (108MW), Willogoleche Wind Farm (125MW), Lincoln Gap Wind Farm (126MW) will all contribute to capacity and some energy into the SA market.

  These new entrant renewable generators are expected to take some market share away from the GPG in SA, putting further cost pressure on these assets to remain economic in a low-cost renewable environment. This is an increase of about 470MW of renewable capacity in SA in the short term.

  This growth in renewables will further reduce the amount of conventional generation that stays in the mix, and is expected to dampen spot prices in SA. The potential positive impact for the market generally is that with reduced spot prices the need to hedge to the same extent as when prices are volatile is lower.

Interconnection can help to improve market liquidity in SA

Against a background of declining market liquidity, a new interconnector can be expected to have a number of positive impacts on the level of forward contracts in SA:

- Further developments out to 2028 as noted in the ISP include utility scale storage of about 650MW (without Snowy 2) and about 230MW (with Snowy 2), up to 975MW of additional wind and solar (without Snowy 2) and 230MW (with Snowy 2).

  Even though there is a potential for further withdrawal of GPG post the SA - NSW Interconnector, namely the withdrawal 1,462MW of baseload gas generation[2]), the addition of utility scale storage and interconnection will be positive developments to stemming the loss of hedging counterparties in SA.

  Our expectation is that the market will utilise utility scale storage and embedded distributed storage in a way that effectively provides a physical hedge to spot price volatility. For example, a large customer could have exposure to the spot market and utilise battery storage to supply electricity when the spot price is high. This wouldn't be an optimum hedge for underlying high prices, but could act as a cap for short periods. However, the expectation is that as the development of low-cost wind, solar and storage solutions increase penetration across the market, the impact on prices will be downwards.

[2] 1,462MW of CCGT within AEMO's ISP by about 2024/25 is expected to be just after the projected completion of the SA to NSW Interconnector. It is likely however that with increased natural gas costs and increased penetration of renewable generation, there will be greater pressure on Osborne PS to retain its economic return to its shareholders. The forecast retirement would most likely occur in any case given the rate of rooftop solar, embedded and large-scale renewable projects in SA over this short term to mid-2020.

- The ability to utilise both the Heywood Interconnector and the SA - NSW Interconnector for inter-regional hedging utilising settlement residue auction units and also local utility scale storage plus peaking GPG will assist in the ability of parties to manage spot price risk.

  Both interconnectors will add over 1,300MW of inter-regional hedging capability between SA and Victoria and SA and NSW. Even though there is expected to be some basis risk due to the risk of interconnector outages, this is expected to be low given the double circuit configuration of both interconnectors.

In summary, SA and the NEM is moving rapidly towards increased renewable and storage solutions. As coal fired generators retire due to end of economic life and GPG gets further displaced by lower cost renewable generation facilities, the market will need to adapt to alternative risk mitigation structures. The traditional hedging structures that currently exist in the market will have to evolve as liquidity is expected to tighten in all regions. The need therefore to consider risk mitigation via utility scale storage, distributed generation, renewable firming products, demand side management and cross region sharing of generation resources across interconnectors are all mechanisms that could replace the volumes of hedging contracts that will be removed from the market as conventional generation exits the market.

2 Introduction

2.1 Background

ElectraNet has undertaken a public consultation process covering the proposed 800MW Robertstown to Wagga interconnector, which has been identified as the preferred option (referred to as “Option C3”) in its South Australian Energy Transformation (SAET) Project Assessment Conclusions Report (PACR) following the Preliminary Assessment Draft Report (PADR) released in mid-2018.

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ElectraNet received submissions related to the SAET PADR and has considered these in addition to modelling from the Australian Energy Market Operator’s (AEMO) Integrated System Plan (ISP). The ISP forecasts that over a 20-year period, there will be a substantial retirement of conventional generation as they reach end of plant life. The modelled impact is that about 70,000GWh of electricity generation will be retired from the NEM and by and large will be replaced by renewable generation and storage.

As the market transitions, market participants will look to large scale storage, demand side mechanisms and alternative risk mitigation derivative structures to manage risk as hedging liquidity from the traditional sellers (being conventional generation) starts to diminish. Large customers that are market facing are also expected to invest more heavily in distributed generation, including storage to provide a physical hedge to spot price volatility.

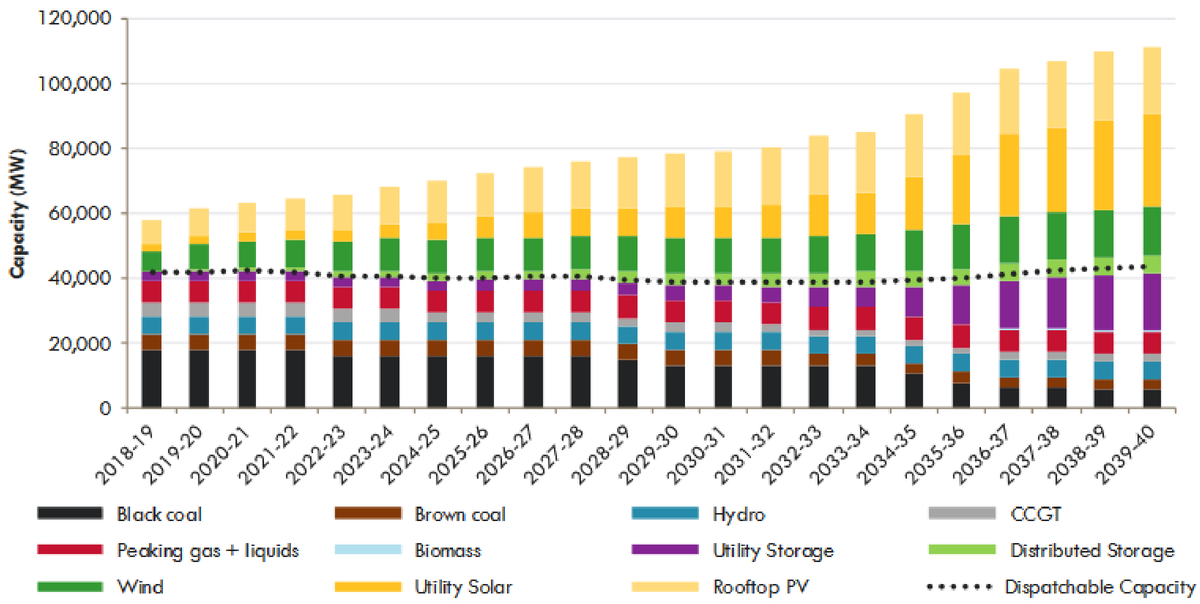
AEMO projects that the replacement of the 70,000GWh of retired generation over the next 20 years will come from 28,000MW of solar PV, 10,500MW of wind and 17,000MW of storage (90,000MWh) and complemented by 500MW of new gas generation.

The combination of lower marginal cost renewable generation is expected to dampen the underlying spot price of electricity, particularly in an environment of greater interconnection between regions. The addition of significant storage in the form of utility scale batteries and hydro (via Snowy 2 or similar), in combination with new fast start and flexible GPG is also expected to reduce the level of price volatility in the market.

The following graph shows the expected change in generation mix across the NEM over the ISP period to 2040. What is apparent is that as conventional generation (particularly coal) is phased out due largely to economic and end of life retirements, utility scale and distributed storage fills the void. Effectively the level of dispatchable generation capacity reduces marginally from 2020/21, but is reasonably steady at 40,000MW across the ISP planning period. As black and brown coal exits the market, utility storage is the main form of replacement. Even though storage can provide price risk mitigation, it can’t do it to the full extent conventional generation can. That is, battery storage is usually limited to a discharge period of 1 or 2 hours, so it will tend to provide risk protection against short duration price spikes whereas conventional generation provides risk protection against underlying price volatility over longer periods.

In this sense the utility storage will add to the cap type products that are already provided in the market by OCGT plant. The difference however is that with greater distributed generation and storage, large customers will be able to materially reduce the spot price volatility they experience in the market and this will more than likely reduce the reliance on having to run OCGT plant as much, ultimately softening the spot price on average.

Figure 2 AEMO ISP - Forecast NEM Generation Capacity in the Neutral Case



Source: AEMO Integrated System Plan – July 2018

The inclusion of a new SA - NSW Interconnector may have some positive impact on hedging liquidity in the short term as the market transitions to with more renewable generation and storage. The timing of the exit of TIPS A (2019/21) and 1,462MW of baseload gas plant (2024/25) post the interconnector will effectively remove approximately 1,100MW from the market which will impact further on hedge liquidity. Nevertheless, the addition of AGL's Barker Inlet (210MW) during 2019 and a forecast of utility scale storage of about 233MW with Snowy 2 and about 650MW without Snowy 2, should account for much of the loss. SA Government's Grid Scale Storage fund and Home Battery Scheme will also assist.

The SA - NSW Interconnector is also expected to aid inter regional hedging between NSW and SA when the flow of electricity is expected to be from a lower priced NSW region into SA.

2.2 Scope of Works

The scope of this engagement comprises analysis and assessment of the following elements:

1. The level of liquidity in the South Australian wholesale contract market now and in future without increased interconnection:
   a) Based on existing conventional generation and future generation mix, the liquidity on the ASX and also current utilisation of SRA's on the Victoria to SA interconnector.
   b) Provision of information on firming products to renewable projects and how this works and the impact it will have on renewable generators being able to offer firm generation into the market.
2. The effect of increased interconnection should the preferred option go ahead, on the level of firm hedges in South Australia:
   a) Consider the level of inter-regional trade with NSW using the new interconnector and how this would impact on liquidity.
   b) Improvements to outage operation with two AC paths.
   c) Intra-regional generation developments (as per confidential submission).
3. The effect of Snowy 2.0 and the preferred option as described in Snowy Hydro's submission and another confidential submission to the SAET RIT-T PADR:
   a) Consider additional base load generation at Snowy and the likely impact this would have on providing additional SA liquidity on the ASX.
4. Any other potential options to support increased wholesale market liquidity in South Australia such as, but not limited to, the recommendations from the ACCC's Restoring Electricity Affordability and Australia's Competitive Advantage 2018 report:
   a) Review ACCCs report and provide commentary.
   b) Provide alternative products that would assist in the market liquidity in SA.

3 Background to Electricity Futures Contracts Markets and Liquidity in SA

3.1 Importance of Liquidity

- *A deep and liquid forward contracting market is essential for spot price volatility mitigation.*
- *As the spot price varies from -$1,000 to $14,200/MWh each trading interval, NEM participants require a competitive forward contracts market to manage spot price risk.*
- *Traditional suppliers of forward contracts are conventional generators that supply electricity into the NEM. Traditional buyers of forward contracts are retailers and large customers. Retailers generally sell fixed priced electricity contracts but need to hedge the floating spot price that is paid to purchase electricity from the NEM.*
- *Traditional suppliers of hedges in SA are AGL, Origin and Engie as they own the bulk of conventional generation plant in SA. One of the issues with this situation is that they are also vertically integrated businesses with their own retail portfolio's, which means they are selling hedging contracts to competing retail businesses looking to compete with them for retail market share.*
- *There are financial institutions that from time to time offer hedges in SA and effectively are making a market as they don't have access to physical delivery of electricity to the market. These counterparties will generally sell at a premium to where the market is trading.*
- *Retail competition in SA is already reduced due to the lack of hedging instruments, leading to increased electricity pricing outcomes for consumers. This can change in a market that encourages new retail competition. The new interconnector and additional distributed and utility scale storage may allow retailers to better hedge their retail exposure in a fast-changing environment.*
- *With the removal of low-cost coal power stations such as Playford and Northern Power Stations, SA is now heavily reliant on higher cost GPG to not only provide energy but also hedging instruments into the market. With the increased cost of natural gas over the past few years, the marginal cost of electricity is usually being set by gas fired generators and these generators are also setting the price of swaps and caps in the market. Ultimately the pricing point has already increased materially, influencing the shift to more wind and solar and greater uptake by customers of distributed energy solutions.*
- *The energy market is now in a position of having to transition to a low carbon environment without the benefit of a low or even moderately priced gas market. Therefore, the necessity to create alternative mechanisms to mitigate risk and lower spot prices on average will be needed. The increase in new renewable build over the next 2 decades, the increased utilisation of distributed generation and the ability of utility storage to manage price volatility will be increasingly important.*
- *We also note that the ability of regions to hedge inter-regionally will also be important and the SA - NSW and Heywood Interconnector will increasingly be important to facilitate the flow of lower cost electricity into other regions but also will also assist participants to hedge risk as traditional sources of hedges exit the market.*
- *The transition into greater renewables, storage and interconnection is likely to allow new entrant retailers to compete for some market segments of the SA market, as lower cost options to contract and manage risk are provided to the market.*

Commodity liquidity is a measure of market efficiency. In the context of electricity markets, it is the extent to which electricity can be purchased or sold without incurring significant transaction costs or impacting its underlying wholesale price. A high level of liquidity is an indication of a strong market, where the price reflects the 'true value' of a commodity relative to changes in its supply and demand. A liquid market is typically characterised by a large number of participants, all willing to buy and sell at any point in time. Conversely, a market with a low level of liquidity often has limited price transparency, lack of depth where larger trades can often impact on available supply and potentially move the market in terms of price. Illiquidity and lack of depth in electricity futures markets makes it difficult to manage price risk association with the underlying physical spot market that you are transacting in.

Therefore, with electricity markets such as the NEM, where all electricity is bought and sold through a centrally dispatched market that sets the spot price, there is a necessity to have an efficient electricity futures contracts market through which participants can manage spot price volatility. This is particularly the case where 5-minute prices can vary from -$1,000/MWh to $14,200/MWh. Markets with this level of price volatility should and must have a robust and efficient hedging market to manage price risk, as the risk of selling fixed price electricity but buying at the prevailing floating spot price can be financially unmanageable.

The ability to manage price risk has often been overlooked in the NEM as a reason for inefficient retail pricing, often the focus is on other regulatory undertakings such as renewable uptake and whether Australia is meeting is climate obligations and what the impact will be on wholesale prices. Rarely is there a discussion about how new entrant retailers manage volume and price risk and whether the hedging market is effective in ensuring efficient and competitive pricing to consumers.

The traditional suppliers of futures (hedging) contracts in the electricity market are conventional generation facilities as they are best able to provide the physical supply of electricity to the market to fulfil their obligations against the futures contract. The traditional buyers of hedges have been retailers and large market facing customers that have exposures to the spot price and look to mitigate high and/or volatile spot prices. Vertically integrated 'gen-tailers' are usually able to manage price and volume risk internally between their generation and retail positions, however retailers that do not have generation would need to ensure that they are able to hedge risk around offering fixed priced contracts and being exposed to a spot price that can be volatile and can clear above their contract pricing.

In SA, only AGL Energy, Origin Energy and Engie through its Simply Energy retail business have retail exposures that are capable of being managed through a generation portfolio. Other retailers that don't have generation positions in SA will generally find it harder to have competitive retail pricing as they will invariably need to find a way to hedge against the potential price volatility of that retail load.

We note however that even for the incumbent vertically integrated retailers, the increase in the underlying cost of electricity (effectively resulting from the increase in natural gas costs) means that the cost of electricity contracts and hedging instruments invariably will be higher. In addition, conventional coal plants are expected to retire in line with economic life cycle and not be refurbished or replaced. Again, the cost of hedges is likely to increase as conventional plant gets mothballed within the NEM.

To break this cycle will need either a significant reduction in the cost of natural gas so that GPG can truly be the interim plant type to transition to a renewable generation future; or the market adapts to be more efficient in its distribution of electricity between regions, more effective utilisation of distributed generation and storage to reduce reliance on grid connection and utility storage that can assist (at least for short periods of duration) price volatility that may be experienced in a predominantly renewable generation mix. A hope for lower gas prices during the forecast period, but certainly in the short to medium term is unlikely and therefore the market must focus on alternative mechanisms to both reduce the underlying cost of electricity as well as putting in place mechanisms to mitigate price risk.

As more intermittent generation plant has been developed across the NEM and some retirements of conventional plant have occurred, the natural depth of supply in these markets have reduced, leading to increased pricing and risks that are now being shared across market participants. There is also a fuel aspect to the market at present, as gas tends to set price as the marginal cost of generation, with markets generally converging in terms of spot pricing. This means that the underlying cost of electricity is increasing and the associated cost of hedging in the market is also increasing.

There have also been financial intermediaries that have taken short positions in the market in an attempt to make a market where liquidity has been poor. Taking a short position in the market is obviously risky and as the market becomes tighter from a liquidity perspective, then the risk premium attached to these hedges will generally be high.

Since 2015, the SA electricity market has witnessed falling liquidity in futures contacts, resulting in higher transaction costs for retailers and large consumers that are market participants. This has resulted in many second and third tier retailers not being able to service the large customer and small to medium enterprise (SME) customer segments in SA. What was and is now more prevalent is that retailers that are not vertically integrated (with generation assets located in SA) are finding the price risk associated with retailing electricity in SA too high to manage. The lack of liquidity in forward contracts is already a reality in SA.

The closure of Northern Power Station and a reduction in the output of Pelican Point[3] in subsequent years significantly reduced liquidity in the SA market of forward electricity contracts. The closure of Northern PS meant that SA no longer had a low-cost base load generation facility, instead its generation is now largely reliant on gas generation (which had an increasing underlying cost of gas), wind, solar, batteries and a growing reliance on interconnection with Victoria to meet network security.

The issue for the NEM more generally however is that the issues facing SA will likely occur in other regions as large low-cost conventional generators retire and are replaced by intermittent generation, with higher cost gas plant having an increasing role in managing system reliability. As this eventuates, the expected liquidity in electricity futures contracts will reduce, making it more difficult to manage price risk.

What was evident post 2015/16 in SA, was a significant drop in market competition for large customer retail offers. Large commercial & industrial (C&I) customers and many SME's could only receive offers from the three vertically integrated retailers in SA. Retailers that didn't have access to self-generation generally found it too risky to offer retail contracts that could not be adequately hedged. This has reduced the competitiveness of electricity retail offers in the SA market, forcing a number of large customers to consider embedded generation solutions and long-term power purchase agreement (PPA) structures from intermittent renewable generation facilities as alternative electricity procurement strategies.

The market is now transitioning quickly where the cost of electricity is driving alternative outcomes for both customers and new entrant retailers. Large customers increasingly are looking at distributed generation and storage as a way to lower their cost of electricity and if exposed to the spot market, storage is a mechanism to reduce exposure to high prices. For new retailers, the ability to utilise access to renewable generation (either as an off taker, aggregator or owner) in conjunction with access to storage and greater inter regional hedges may well create more retail competition into SA. However, this will take some time as the market transitions.

[3] Pelican Points generation output has varied over the past few years, possibly due to its gas contracting arrangements and also its retail contract position. So, contract liquidity can fluctuate slightly depending on the operational status of Pelican Point and also how much hedge volume they make available to the market.

3.2 Intermittent Generation and Firmness

- *As the market transitions away from coal and some GPG to greater capacity in wind, solar and utility storage, there is a need or want by the market to consider better 'firming' of intermittent plant.*
- *Retailers that used to enter into power purchase agreements (PPA) with renewable project developers are now more cautious about having too much intermittent generation in their portfolio, which can make it difficult to provide fixed price electricity contracts to end consumers.*
- *In order for renewable projects to reach financial close they will usually require a reasonable level of PPA term and price in order to attract debt/equity investment. As the pipeline of renewable projects are growing, there is ultimately a race to try to obtain PPA's in order for the project to proceed. The primary issue with this is that the appetite from retailers to enter into PPA's has diminished and therefore the market has moved to alternative firming structures to underpin the revenue of a project.*
- *The market has now seen the introduction of proxy revenue swaps and balance of hedge products underwritten through reinsurance businesses, which look to provide revenue certainty for renewable projects.*
- *These derivative structures are new to the market and have been struck across both wind and solar projects.*
- *What these structures will provide is to increase the number of renewable projects that will ultimately reach financial close and be commissioned, leading to greater energy being provided to the market. As a consequence, some of the bottlenecks in getting projects to market are being resolved through new and innovative financial instruments.*
- *As modelled by AEMO, the market is expected to experience significant renewable and storage projects over the following decade and this will no doubt dampen spot prices, potentially reducing the level of risk that sits in the underlying spot market.*
- *It is our expectation that as more renewable projects get built, there will be greater access to low priced off-take agreements that large industrial customers can enter into.*
- *The number of renewable projects however will be limited to the extent that they can get energy to market and with limited demand in SA and existing interconnection into Victoria currently being constrained, the SA - NSW Interconnector will allow for energy to flow both from NSW into SA but importantly also from SA into NSW.*

One of the downsides to the growing intermittent generation market has been that they have not historically been able to offer "firm" PPA structures to large customers or retailers, effectively putting the risk on the buying counterparty to the spot when the generation plant is unable to produce electricity. Over the past 3-4 years in particular, there has been an exceptionally large pipeline of renewable projects that have required long term PPA structures in order for them to become financially viable.

The traditional buyers of electricity from these renewable projects are the retailers, renewable aggregators that on sell the electricity and large customers. The obvious issue is that with intermittent generation in a portfolio, someone has to carry the risk of non-delivery of electricity to the market. This is usually done by retailers having a diverse electricity portfolio or customers being able to demand side manage or utilise storage devices such as battery storage or diesel generation to back up the mismatch between intermittent generation and demand. Ultimately this comes at a cost and the cost of hedging this level of non-firmness has generally meant that these projects become less competitive from a pricing perspective as compared to traditional conventional generation plant.

As retailers take on more intermittent generation into their portfolio, they too face the risk of having to manage this volume risk. At the same time as the market is transitioning into cheaper wind and solar generation (from a short run marginal cost perspective), the projection of spot prices is softening, putting pressure on PPA structures that require a 10-year contract term. The great uncertainty in potential market outcomes creates a risk that customers can sign onto a long term

PPA that is out of the money. So, the trend has been moving away from long term PPA structures as the market becomes more saturated from a renewable generation perspective. So, breaking this nexus of needing to achieve a PPA and usually one with a long term and finding a retailer or large customer to contract means that the market is introducing alternative firming structures for intermittent plant.

The introduction of "synthetic" firming products is now available to intermittent wind and solar projects, that effectively provides the project with a fixed revenue stream with a contract for difference (CFD) to the underlying spot price. In a limited PPA market, these synthetic proxy revenue structures are becoming more sort after as a viable alternative to reaching financial close on projects. However, these firming products are not seen as a mechanism that would allow an intermittent plant to offer hedge contracts as conventional generators are able to do, but rather the firming product is a way for intermittent plant to be underpinned through a fixed versus floating structure that mimics a traditional PPA. Unless intermittent plant also has a form of storage or reliable backup generation, it will be difficult for them to offer hedges into the market.

4 SA Electricity Market and Hedge Position

4.1 SA Spot and Forward Contract Pricing

- *The linkage between the expected future spot price and the forward swap market is relatively strong.*
- *When the market expects spot price volatility, a shortage of hedge supply, market constraints or changes in fuel costs, there will usually be a strong correlating movement in the contracts market.*
- *As the underlying spot price becomes more volatile, then the demand for hedges is usually strong to try to mitigate against that price volatility and those selling contracts will want to ensure that they have adequately priced the forward contract. At these times the price premium is high to reflect supply shortages or just uncertainty of potential future spot price outcomes.*
- *In SA, the spot price is largely driven by the marginal generator which invariably is a gas fired generator. During 2010 and 2011, the SA spot price following normal economic theory, i.e. that when demand is high, the price is set by costlier open cycle gas turbines. This relationship is not that strong anymore as high and volatile prices are no longer just set during high demand periods. Price can now reach the market cap during low or average demand periods with significant amounts of renewable generation operating in the market, as fast start plant plays a greater role in balance supply/demand.*
- *The problem that SA faces is that conventional plant and balancing plant in SA is gas fired. TIPS A and B, Pelican Point, Osborne, Quarantine etc are all gas fired. The cost of gas has increased materially over the past 4 years (effectively doubling to about $10/GJ) and as a result the cost of generating electricity has increased in SA when local generation sets price.*
- *When looking at the spread of quarterly swaps in the market, in the past 2 years the price spread has increased substantially. This increasingly is a symptom of increasing costs of producing electricity from conventional generation facilities (as the primary suppliers of these hedges) and also that the NEM is seeing a tightening of demand and supply for hedge products, creating a premium on price. SA is not the only region that has experienced this phenomenon, with Victoria and NSW also experiencing similar price spreads as large coal-based generators start to exit the market.*
- *The difference in SA however is that the hedge price is generally clearing well above the underlying spot price over recent periods as compared to Victoria and NSW where the spot price is clearing close to the average hedge price as transacted during the prior 12 months. This is most likely just a result of poor liquidity in SA as compared with NSW and Victoria.*
- *As the market transitions to a low carbon market, there was an expectation that gas would be the ideal transition fuel for generation. It would provide a generation mix that suits intermittent generation and therefore is a natural fit. However, the cost of natural gas is too expensive for it to be the interim fuel for electricity generation.*
- *This is not just a SA problem but will be faced in other regions as coal generation exits and gas becomes the marginal generator that sets price.*
- *What is transparent is that the market is now looking at leapfrogging gas by building significant distributed generation and storage as well as utility scale storage to reduce the reliance on gas generation.*
- *The SA - NSW Interconnector will assist in this transition away from coal as a high carbon intensive fuel and also gas which is too expensive relative to renewable alternatives. As renewables get built, they will need to get access to market and current restrictions in SA can be lifted when increased interconnection is built.*
- *The short-term issue however is to bridge the gap in terms of how this impacts on hedging contract liquidity. The market will adapt, but SA may find liquidity becomes even worse in the near term with the withdrawal of more conventional generation. Additional interconnection will assist generation supply resource sharing as well as inter-regional hedge capability (subject to interconnector flows).*
- *Ultimately as more renewables get deployed in SA and across the NEM, the average cost of producing electricity will come down, providing greater choice for customers and reducing the need for hedges.*

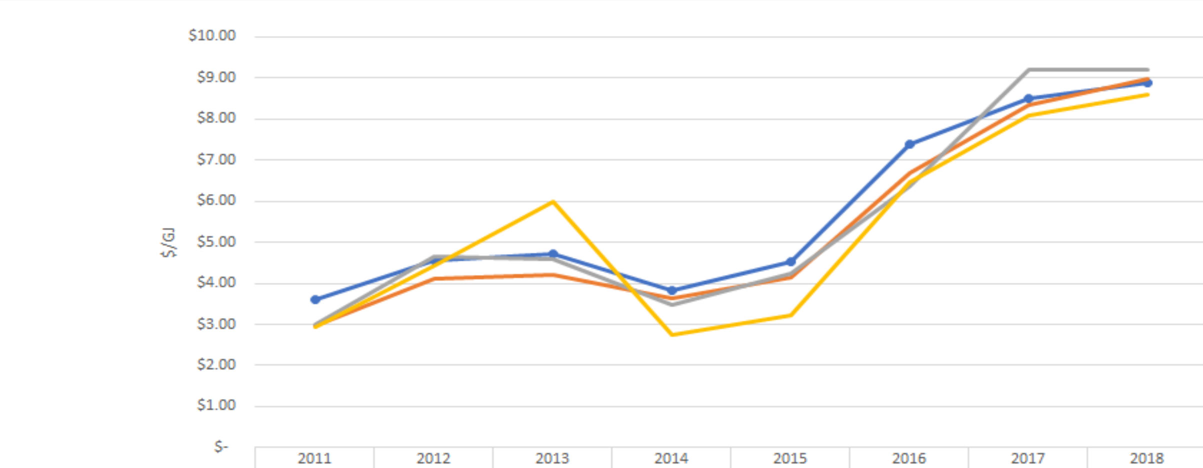
The following section is confined to the trade of SA forward contracts and hedging products via the Australian Stock Exchange (ASX). Forward contracts (hedges) can also be traded over the counter (OTC) or directly between counterparties, in addition to the ASX. We have assumed that the ASX trades will provide a reasonable picture of the cost and liquidity in the SA market for base forward contracts. The OTC contract market is not transparent and as a result has not been factored into this report. This report also only considers vanilla flat swaps and caps through the ASX. We note that there are a number of other hedging style products in the market such as Asians, Captions etc, but this report just considers the vanilla style products in the market.

The electricity flat swap products are effectively a hedge that looks at forward expectations of where the underlying spot price is likely to settle. If the market expects a volatile spot period, a shortage of generation, a lack of swap contract supply, then this would usually flow through into higher priced hedges. A swap would usually be the preferred hedge for managing underlying spot price volatility below $300/MWh, whereas a $300/MWh cap would be more favoured when underlying spot prices are expected to be relatively flat but with occasional high prices materially above $300/MWh (usually reaching the market cap).

What SA has seen over several years is that spot prices have increased on average but not necessarily in terms of extreme volatility (i.e. the number of price cap outcomes haven't increased, but the underlying cost of electricity has). One of the major contributing factors to this is the cost of natural gas as an input cost to electricity generation. Gas contract prices have generally doubled in the past 3-4 years from about $5-$5.50/GJ to about $10/GJ +. This means that for a plant like Pelican Point with a heat rate of about 8GJ/MWh, its fuel cost has gone from about $40/MWh to about $80/MWh. This excludes the variable and fixed operating and maintenance costs associated with the generator.

Therefore, the price that reasonably efficient plant in SA (such as Pelican Point) can offer flat swaps for in the market would need to reflect at least the short run marginal cost of the plant plus a risk premium for the hedge uncertainty. The cost of hedges has increased off the back of increased gas prices (as an input in SA of conventional generation) and also relative to the supply and demand dynamics of the quarterly forward contract. The following graphs show the movement in spot gas outcomes and the relative movement on average electricity prices and also the linkage to forward contract prices.

Figure 3 Spot Gas Annual Average Prices – STTM and DWGM



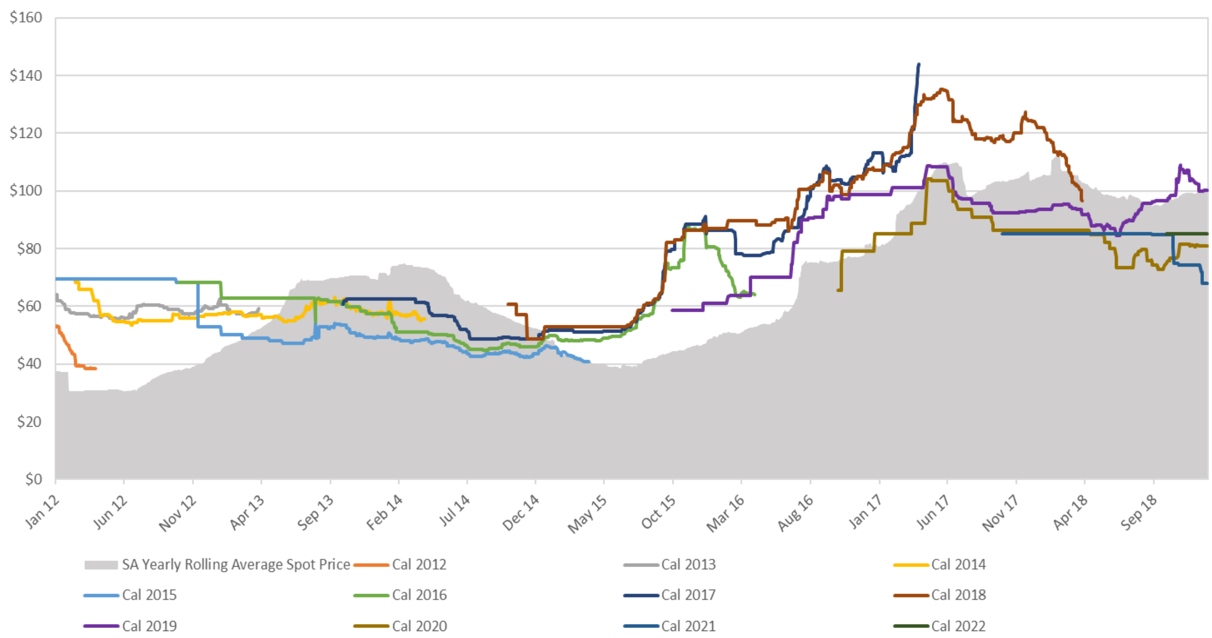
	2011	2012	2013	2014	2015	2016	2017	2018
SA STTM Ave Price	$3.60	$4.57	$4.73	$3.82	$4.54	$7.40	$8.50	$8.87
VIC DWGM Ave 6am Price	$2.98	$4.12	$4.21	$3.64	$4.15	$6.69	$8.35	$8.98
NSW STTM Ave Price	$3.01	$4.64	$4.58	$3.47	$4.24	$6.38	$9.20	$9.19
QLD STTM Ave Price	$2.93	$4.42	$6.00	$2.74	$3.22	$6.48	$8.09	$8.59

Source: CQ Partners using AEMO data (as at 12 November 2018)

Gas price increases are not just SA centric, with escalations in the price of gas experience across the NEM. The outcome has been that cheaper forms of generation are starting to shadow price gas generation plant, ultimately driving up the overall cost of electricity.

Looking at the graph below, we can see a linkage between average electricity spot price and the price of forward swaps in the SA. As the cost of spot prices increased off the back of increased gas prices, a Heywood interconnector outage in July 2016, the withdrawal of Northern Power Station and reduced availability of Pelican Point, the cost of hedges also increased. This is really just reflecting the markets expectation that the spot market will be more volatile and uncertain and as a result the price of hedges need to reflect that risk and uncertainty.

Figure 4 SA - Rolling Average Electricity Price and Forward Flat Hedge Pricing



Source: CQ Partners using ASX and AEMO data

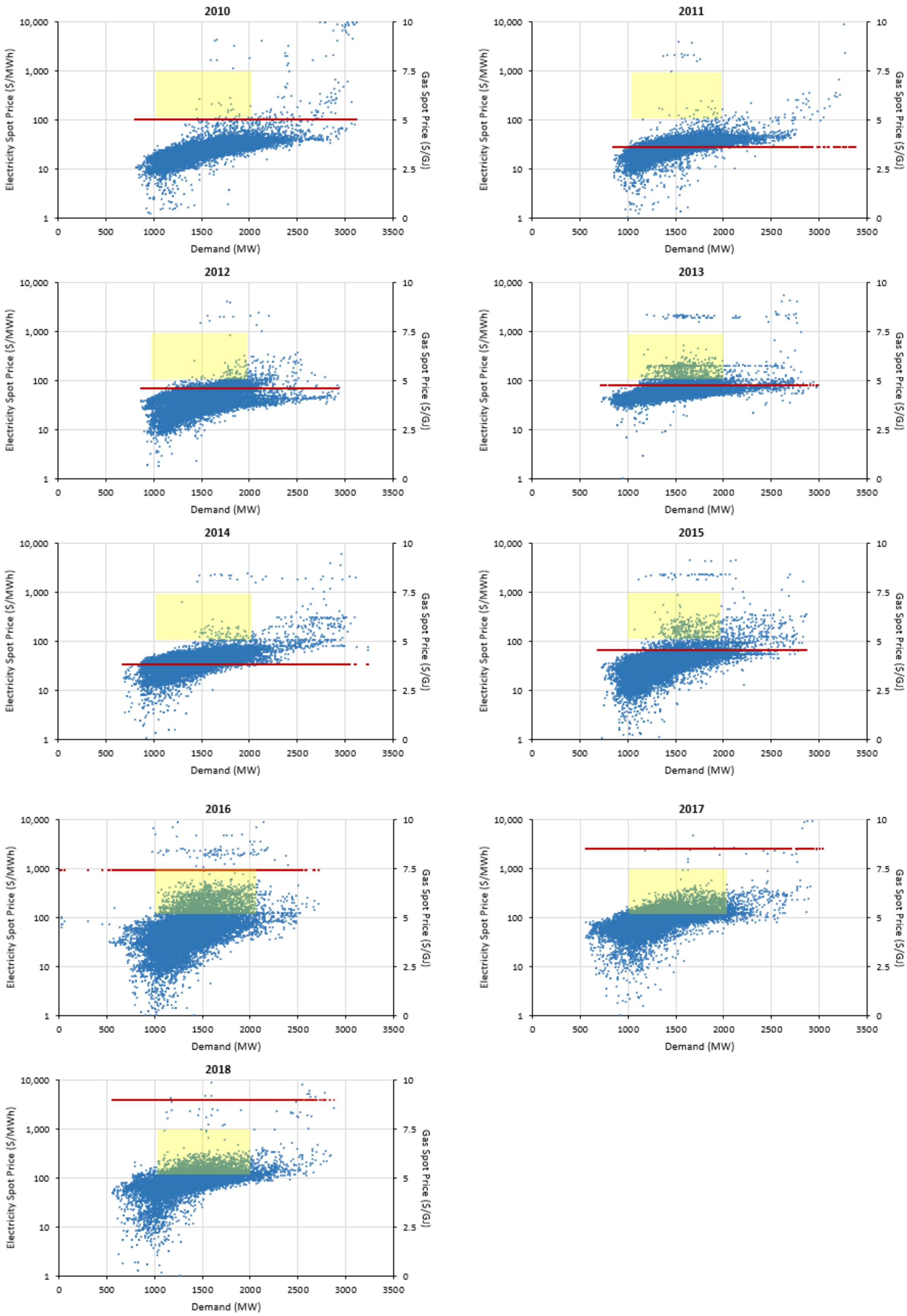
Another indicator of spot price is the price-demand duration curve. In an efficient marketplace, price is usually set by a competitive supply chain responding to demand. So as demand increases, more expensive plant will be dispatched to meet that demand. What we have noticed however is that demand is no longer the main driver of spot price outcomes. Spot price is now as much a function of the fuel costs associated with the marginal cost of generation (usually gas) as this form of generation is most likely used to balance an increasingly intermittent generation base. The price duration curves are illustration in the graphs below.

What the graphs show is that prior to significant wind and solar generation being installed in SA, the price duration curve was as expected, that is, when demand is high, prices too would be high and importantly when demand is low to average, prices were also low. This shows an efficient marketplace where supply and demand dynamics work as intended. This is most evident in years 2010 to 2014 (with 2013 being an exception due to carbon price uplift). However as fast start plant became increasingly dispatched to resolve intermittent generation output, prices started to clear at higher prices during low and average demand periods. This is a sign of a more volatile, unpredictable and inefficient marketplace.

Years 2015 is a good example of this as the cost of gas wasn't yet a factor in higher spot prices, but the market started to experience elevated spot prices at low to medium demand levels. From 2016 onwards, the cost of gas has become more of a determinant factor in underlying spot price outcomes, with significant periods at low demand to average demand clearing between $100-$300/MWh.

The underlying volatility in spot prices as well as the increase in hedging costs and the underlying liquidity issues that have been experienced in SA has flowed through to significant increases in the retail electricity price to customers.

Figure 5 Price-Demand Semi-Log Scatter Plots by year (2010-18 YTD)



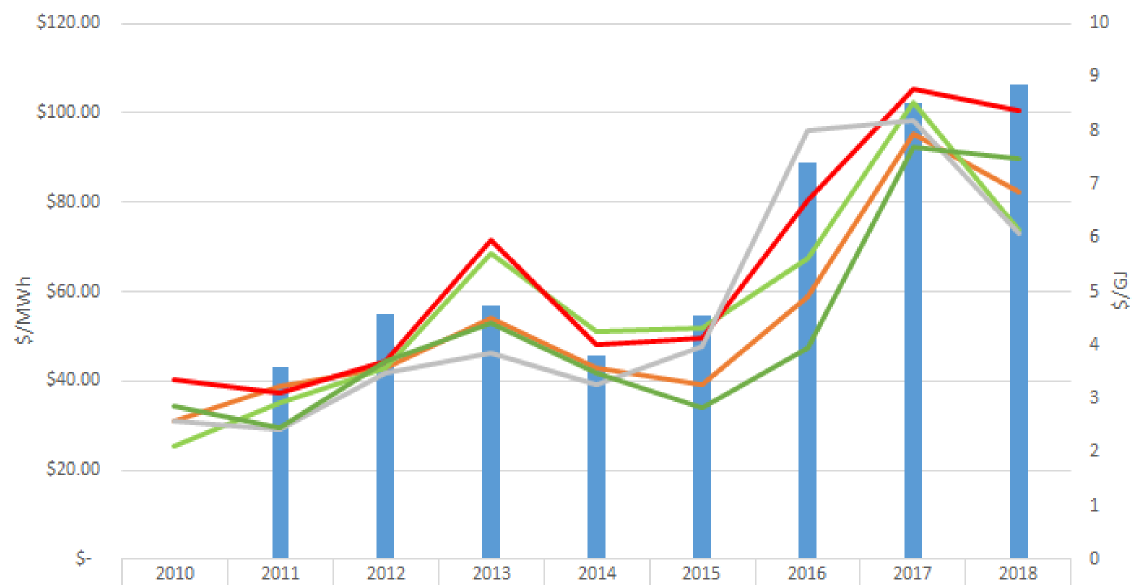
Source: CQ Partners using AEMO data

The underlying SA spot prices has increased over the past few years as illustrated in figures 6 and 7 below. The wholesale price of electricity has grown largely in line with the increase in the cost of natural gas. From 2016, the price of natural gas become linked to LNG export markets, and with the withdrawal of Northern PS from the market, the marginal cost of generation tends to be set more by gas in SA or via the Heywood Interconnector.

As illustrated in figure 6, the average annual spot price increased from about $50/MWh in 2015 to $100/MWh in 2018 (YTD). This is a significant and material change in the market that created a need to mitigate price risk at the wholesale level. SA is not the only region that has experienced such increases in spot price volatility and price increase. The NEM as a whole has experienced spot price changes that largely cleared between $0-$50/MWh up to 2015, now clearing more regularly between $50-$100/MWh.

What this indicates is that as spot price movements can be material, there is significant risk for retailers that are not hedged to mitigate against these price movements. What is also clear is that retailers without a generation position would find it difficult to appropriately price retail offers for large industrial loads. These retailers would need to ensure that they can adequately hedge the retail load and generally this means competing against the gen-tailers who also happen to be the primary sellers of hedges in SA. For this reason, SA has experienced a significant reduction in retail competition for large industrial loads.

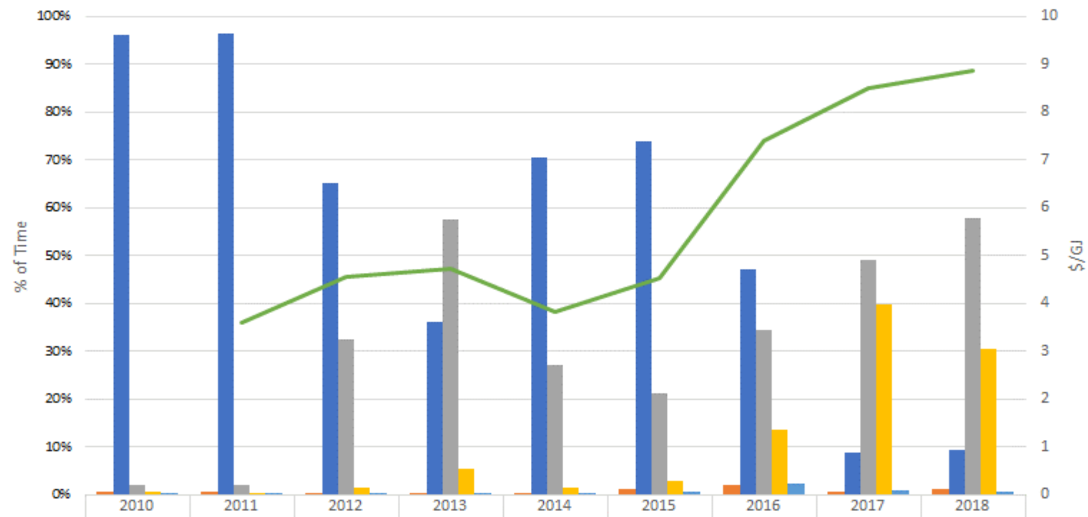
Figure 6 Electricity Spot Price Annual Average and SA STTM Annual Average (2010-18 YTD)



	2010	2011	2012	2013	2014	2015	2016	2017	2018
SA STTM Ave		$3.60	$4.57	$4.73	$3.82	$4.54	$7.40	$8.50	$8.87
NSW	$30.89	$38.91	$43.05	$53.90	$42.78	$39.16	$58.98	$95.48	$82.11
QLD	$25.53	$34.94	$42.94	$68.41	$50.91	$51.96	$67.44	$102.34	$73.61
SA	$40.28	$37.41	$44.21	$71.68	$48.13	$49.58	$80.59	$105.33	$100.54
TAS	$30.89	$29.22	$41.94	$46.28	$39.02	$47.54	$95.89	$98.15	$72.98
VIC	$34.44	$29.37	$44.40	$52.86	$41.62	$33.86	$47.43	$92.22	$89.64

Source: CQ Partners using AEMO data

Figure 7 Price Range Percentage Outcomes by year and SA STTM Average Price (2010-18 YTD)



	2010	2011	2012	2013	2014	2015	2016	2017	2018
-$1,000 to $0	1%	1%	0%	0%	0%	1%	2%	1%	1%
$0 to $50	96%	96%	65%	36%	70%	74%	47%	9%	9%
$50 to $100	2%	2%	32%	58%	27%	21%	34%	49%	58%
$100 to $300	1%	0%	1%	5%	2%	3%	14%	40%	30%
$300 to $15,000	0%	0%	0%	1%	0%	1%	2%	1%	1%
STTM Gas Ave Price		$3.60	$4.57	$4.73	$3.82	$4.54	$7.40	$8.50	$8.87

Source: CQ Partners using AEMO data

What the data also indicates is that the value of $300/MWh caps is less favourable when the majority of price outcomes is settling below $300/MWh. Hedging against price volatility in the current market is therefore best done via swaps, unless there is an expectation that a region or NEM more broadly will be short energy, which will likely see significant price volatility over $300/MWh. This is currently the case with the Victorian region, with AEMO signalling a possibility that there will be a supply shortfall. As can be seen in the figure 8 below, the cost of caps has escalated materially since June this year.

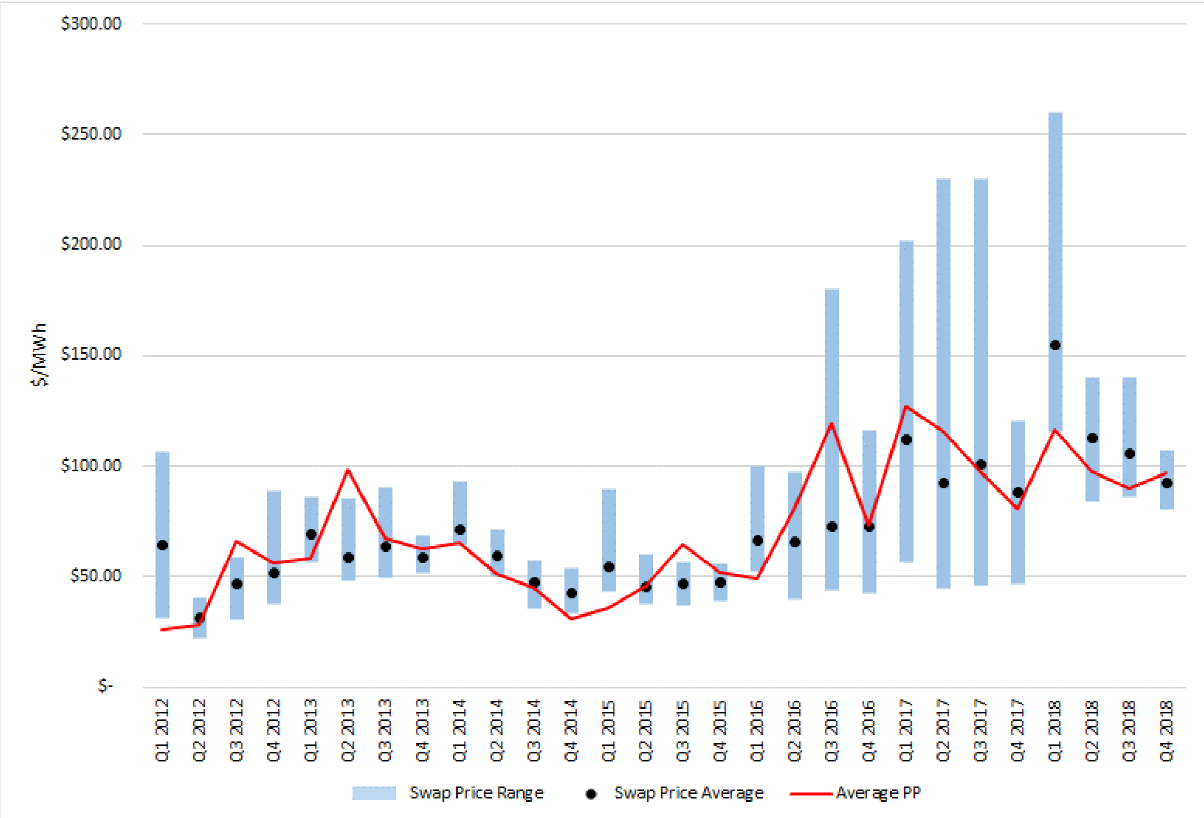
Figure 8 VIC - $300/MWh Caps Volumes and Pricing

Source: CQ Partners using ASX data

Flat swaps in comparison appears to have too much risk premium built into it in recent years and therefore is clearly at a significant premium to the underlying spot price. This can be seen in figure 9 below, which shows that as spot prices have become more volatile and increased off the back of increased gas pricing and greater utilisation of peaking plant to, the price spread of swaps widened significantly as different sellers of the swap attributed difference risk weightings on the hedge.

In recent times the cost of a flat swap has transacted for double the underlying spot price average which indicates an inefficient hedging market. This is compared to the period prior to 2016, which had a relatively tight hedge price spread and where the underlying spot generally cleared within an expected price band. The lack of liquidity in the SA market, due to a small number of suppliers and a reduced volume to be traded has materially impacted on the ability of non-vertically integrated retailers and market exposed customers to manage risk in SA. As a result, there is a flow on effect of reduced retail competition which ultimately leads to more costly pricing to the customer.

Figure 9 SA Quarterly Swap Hedge Outcomes – Min, Max, Ave. Versus Ave Electricity Spot Price



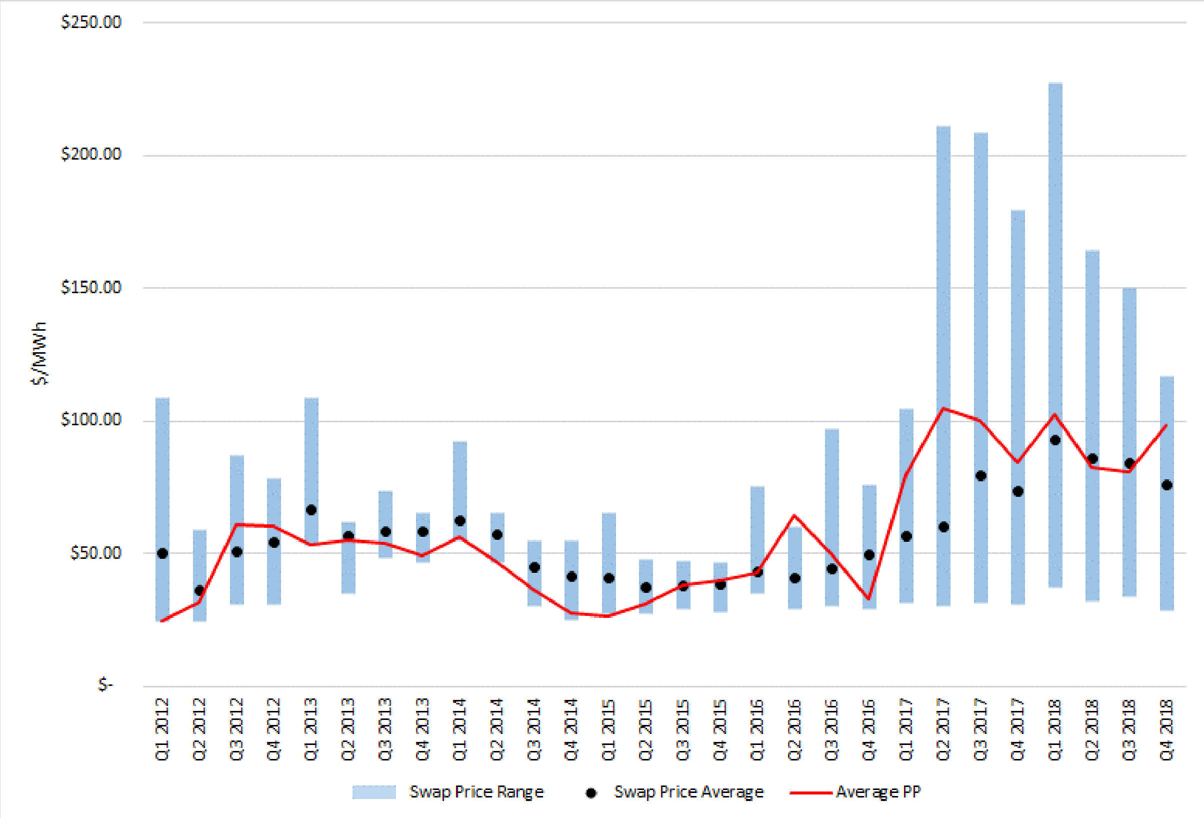
Source: CQ Partners using AEMO data

The data that forms the above graphs (and other similar graphs below) are quarterly swap prices 12 months prior to the start of the relevant quarter. So, it provides a minimum and maximum price that the quarterly swap could have been purchased at and also the average price. What is noteworthy is how wide the spread for quarterly swaps has become over the past 3 years. As the market moves through different phases of spot price volatility and expectations through a year prior to the start of a quarter, the price of that swap will generally get repriced accordingly.

It is interesting to note that since 2012, the SA Q1 quarterly swap has nearly always been overpriced relative to the underlying spot price due to the risk premium suppliers of the hedge puts on this period and also the demand for hedges. This is because demand is usually linked to temperature and summer is still seen as a risky period where demand can be higher, causing volatile pricing. In comparison the Victorian and NSW Q1 pricing does not appear to have the same level of risk premium built into it. This potentially is a function of the liquidity available in these regions, resulting in more competitive hedge pricing.

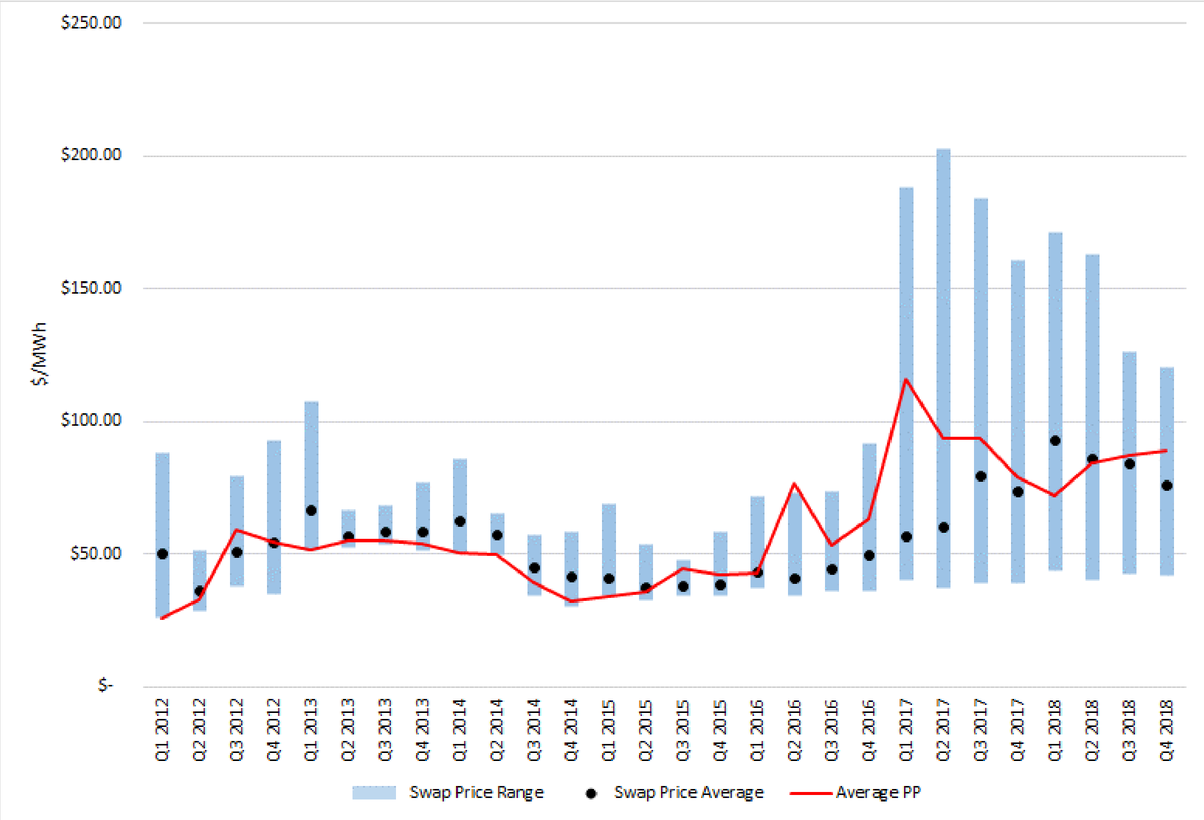
This price spread in quarterly swaps however has also occurred in Victoria and NSW. Again, as spot prices are averaging higher in all regions and as more counterparties look to manage risk, the variability in pricing in the preceding 12 months can vary significantly. What is more evident however is that suppliers are more willing to price swaps at a significant premium to where the underlying spot price is expected to clear and does clear. Again, there is caution here for market participants that have a need to hedge price risk. Ultimately it favours that parties that are vertically integrated with a balanced portfolio of renewables and conventional plant and disadvantages those customers and retailers that don't have any physical or financial hedges in their portfolio.

Figure 10 VIC Quarterly Swap Hedge Outcomes – Min, Max, Ave. Versus Ave Electricity Spot Price



Source: CQ Partners using AEMO data

Figure 11 NSW Quarterly Swap Hedge Outcomes – Min, Max, Ave. Versus Ave Electricity Spot Price



Source: CQ Partners using AEMO data

4.2 SA Forward Market Liquidity

- *The SA forward contracts market has been less liquid post the withdrawal of Playford and Northern Power Stations, particularly in relation to quarterly and flat swaps. This is largely a result of smaller volumes of swap contracts being made available to the market from existing conventional generators in SA.*
- *In SA, TIPS A and B, Osborne and Pelican Point tend to be the primary suppliers of swaps, however there is a level of disfunction in the market already, with demand for hedges outstripping supply. The other issue is that the suppliers of swap contracts are vertically integrated parties that also require risk mitigation to protect their own retail portfolio from high and volatile spot prices. More fundamentally though is that there is a lack of competition in this market, with market facing customers and competing retailers finding it difficult to purchase hedges in an efficient marketplace that provides competitive pricing and volume solutions.*
- *The difficulty for new entrant retailers is that they will invariably have risk policies that regulate how much they should hedge relative to their retail portfolio. There is a catch 22, then in whether to hedge first to get certainty and then try to attract and win a customer, or to win the customer and then try to hedge out that position. This is an extremely difficult market to do either without carrying transaction risk.*
- *Given that SA already has hedging liquidity issues, the question is what impact will the SA - NSW Interconnector have on future liquidity. This question is difficult to determine due to the number of variables that can change the result, Certainly the renewable build rate, the amount of storage (both distributed and utility scale) and the utilisation of proxy revenue swaps and balance of hedge products could change the level of liquidity in the market.*
- *The expectation is that renewable generation will have a dampening impact on spot prices and the utilisation of storage and new firming revenue swaps will lead to more efficient pricing to the end user.*

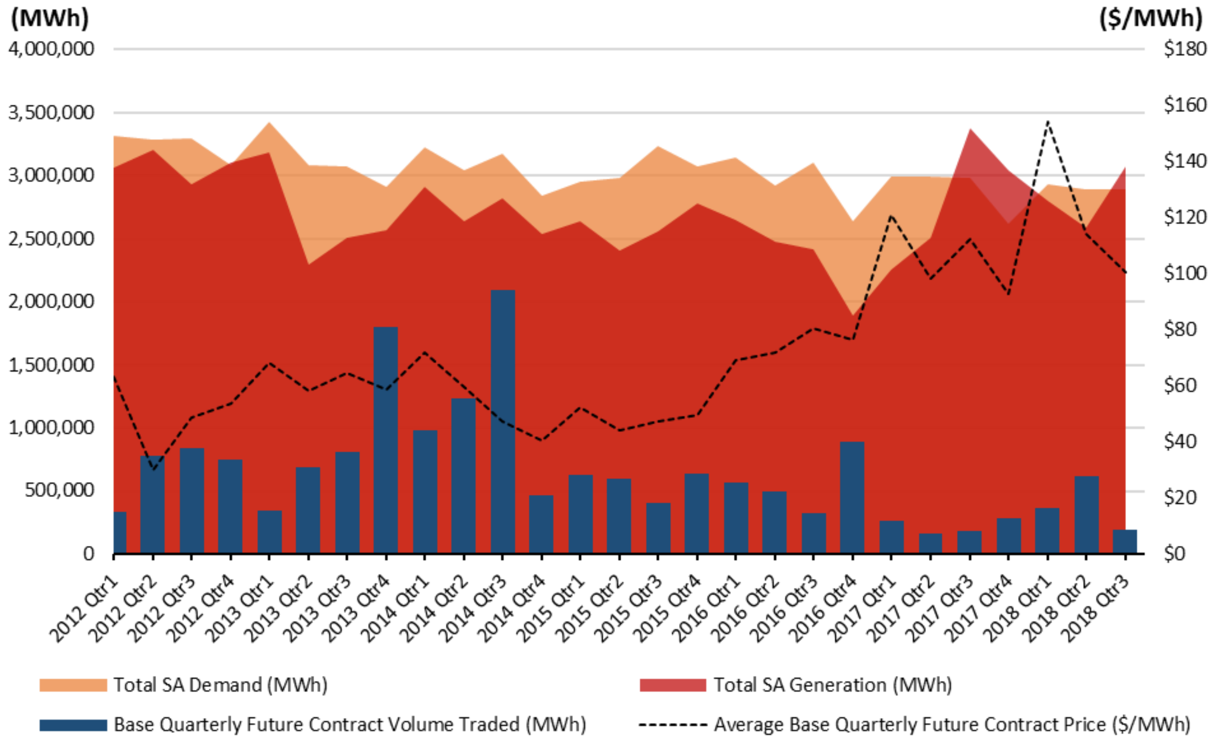
The inclusion of the SA - NSW Interconnector in our opinion is not really the driver of hedging liquidity changing as the retirement of conventional plant will drive this.

- *The Interconnectors between SA-Vic and SA-NSW will fundamentally provide a better spread of resources between regions and allow lower cost generation to get their electricity to market. In the absence of improved interconnection, there is a potential outcome that hedging liquidity will still deteriorate as large conventional generators retire, but participants don't have access to inter regional contracts to assist in the mitigation of price risk.*
- *The SA market will likely see some short-term liquidity issues as TIPS A starts to retire from 2019, prior to alternative instruments such as the interconnector or large-scale storage being developed. The only consolation is that Barker Inlet get deployed as TIPS A get retired.*
- *In the medium to long term, AEMO has forecast significant new renewable generation and storage to be deployed which should assist the market. The market will in the medium to longer term build or find financial solutions to a lack of hedging instruments, particularly if it becomes a NEM wide issue.*
- *In the longer term we note that pipeline projects of renewables and storage within South Australia and the Snowy 2 project will not likely proceed unless there is interconnection to allow these projects to get their electricity to the market. These projects are large and have significant levels of storage incorporated into the project which is expected to aid the level of hedging capability across both SA and NSW.*

SA's market for electricity forward contracts has always been less liquid than the eastern states such as QLD, NSW and Victoria. One of the reasons for this is that SA has a very high proportion of renewable generation to conventional generation capable of supplying hedges. The other reason is that the traditional suppliers of forward contracts also have large retail positions in SA and their retail positions also require hedging. Therefore, the price and volume of available forward contracts in the market is highly dependent on the level of retail contracting by vertically integrated retailers and the level of demand for hedging instruments from third parties.

The following graphs depict the level of demand in SA (which is slowly falling due to energy efficiency measures and increased penetration of solar PV systems), the overall energy generated by SA generators, the volume of quarterly swaps traded on the ASX and the price of those swaps. The first graph (figure 12) shows that even though the amount of energy created in SA has increased, the volume of base quarterly futures contracts is reducing. This is a symptom of having more energy from renewable and peaking generation which ordinarily are not sellers of base swaps. The market is therefore starting to experience a mismatch between the types of generation that provides energy and those that can also provide forward hedges.

Figure 12 SA Generation, Demand, Base Quarterly Futures Contract Volume & Price (2012-18)

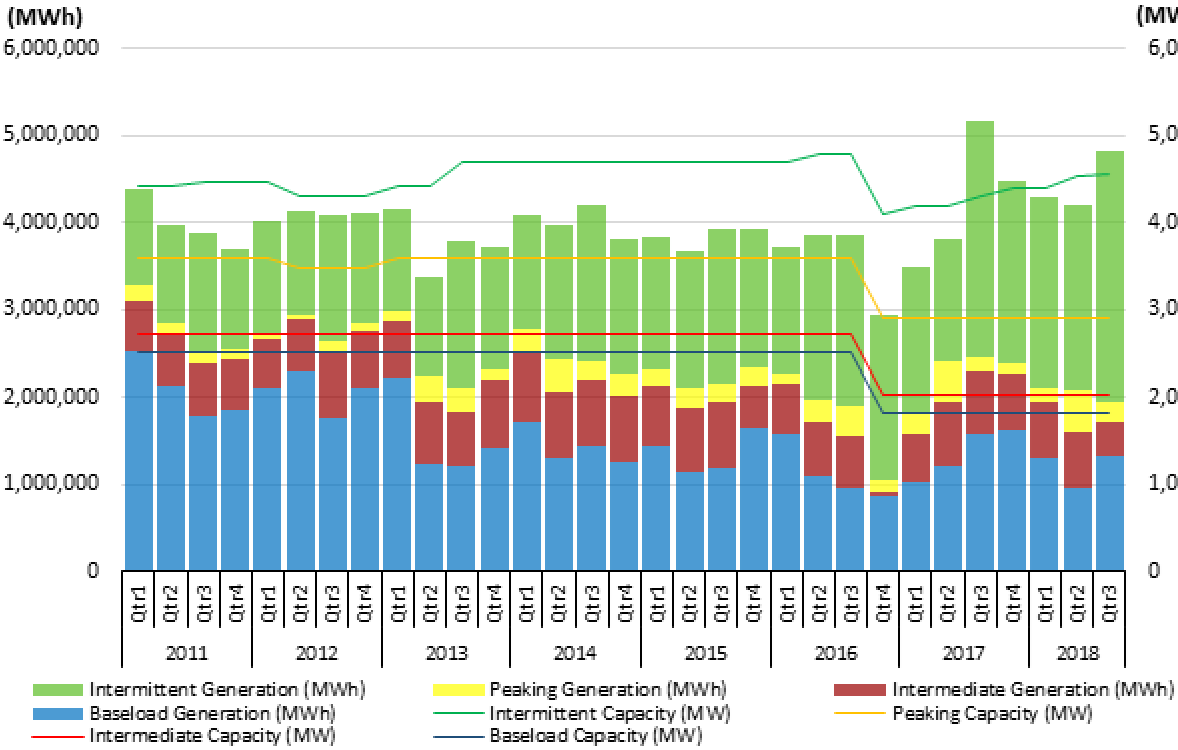


Source: CQ Partners using AEMO and ASX Data

The following graph more clearly shows the level of baseload[4] generation in the SA region that would normally be sellers of flat swaps. As noted in the graph, as Northern PS retired and also with Pelican Point not running at lower capacity across the year (with periods of no or half station generation), intermittent renewable generation and costlier intermediate and peaking plant have increasingly provided more energy into the SA market to meet demand. The issue here is that the underlying spot market has as a consequence become costlier, yet the hedging market has become less liquid, creating increased risks across the retail sector.

[4] Baseload in this instance is TIPS A and B station, Northern PS and Pelican Point. Intermediate is Osborne PS and Peaking is the remaining gas and diesel OCGT generators.

Figure 13 SA Generation, Demand, Base Quarterly Futures Contract Volume & Price (2012-18)

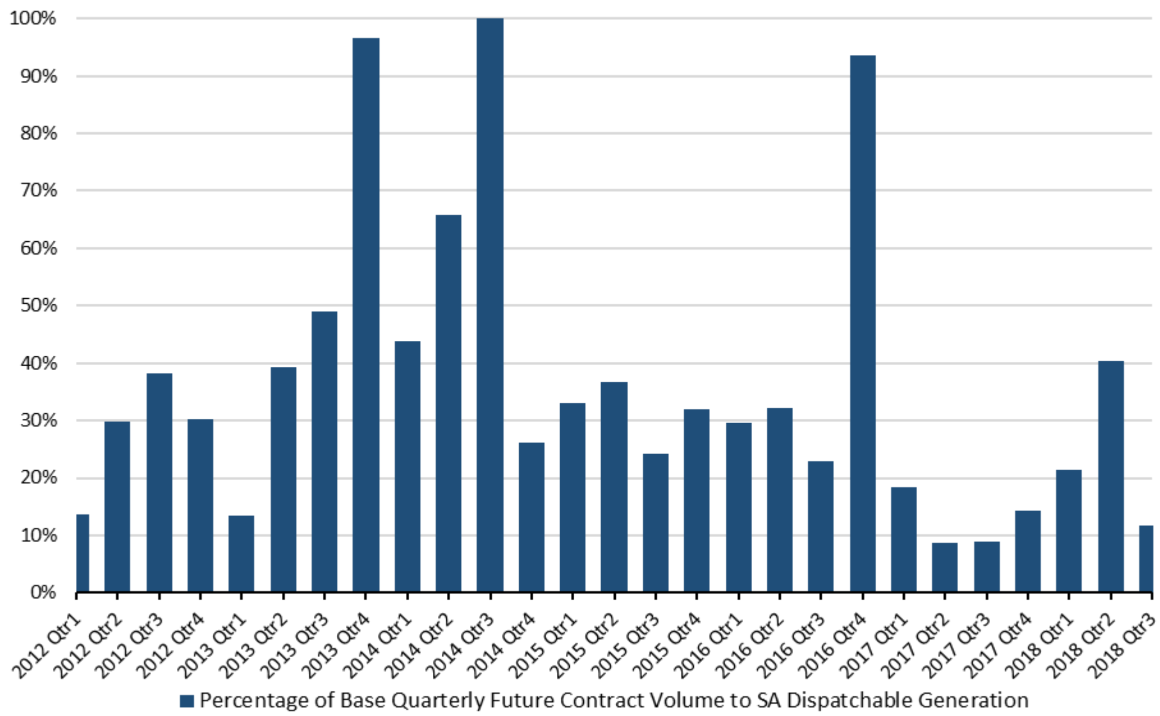


Source: AEMO

Another way to consider the liquidity issue is to look at the volume of base quarterly swaps that have been traded as a percentage of SA dispatchable generation, i.e. only taking into account TIPS A and B, Pelican Point, Osborne Power and Quarantine. It is clear that the volume of hedges as a percentage of dispatchable generation has decreased, with the exception of Q4 2016 when Pelican Point increased its generation from not running to about have its capacity (240MW) being online. At the same time however, Osborne PS came off for much of Q4 and Northern PS was retired in May 2016.

Ultimately, there will be times that the remaining generators will look to sell forward contracts in the market, depending on the market price of the hedge, their portfolio requirements and the underlying risks associated with the spot market at the time.

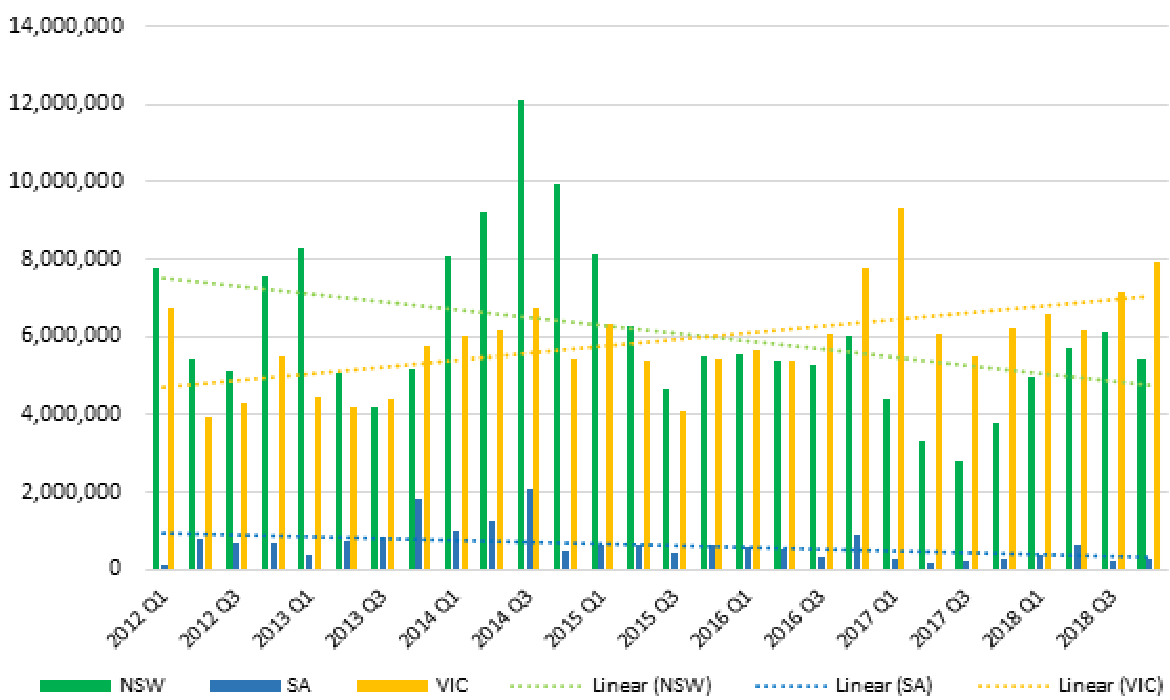
Figure 14 Percentage of Base Quarterly Futures Contract Volume to SA Dispatchable Generation



Source: CQ Partners using AEMO and ASX Data

Comparing the liquidity of quarterly base swaps in SA to that in Victoria and NSW, the following graph indicates the small volumes of swap hedges traded in these regions. SA in comparison is already a very tightly traded market, but what is interesting is that other regions that also have large conventional plant that will retire over the next decade will start to experience reduced liquidity as well.

Figure 15 Volume of Energy Hedged in SA, VIC and NSW – 2012 to 2018 and trendline



Source: CQ Partners using AEMO and ASX Data

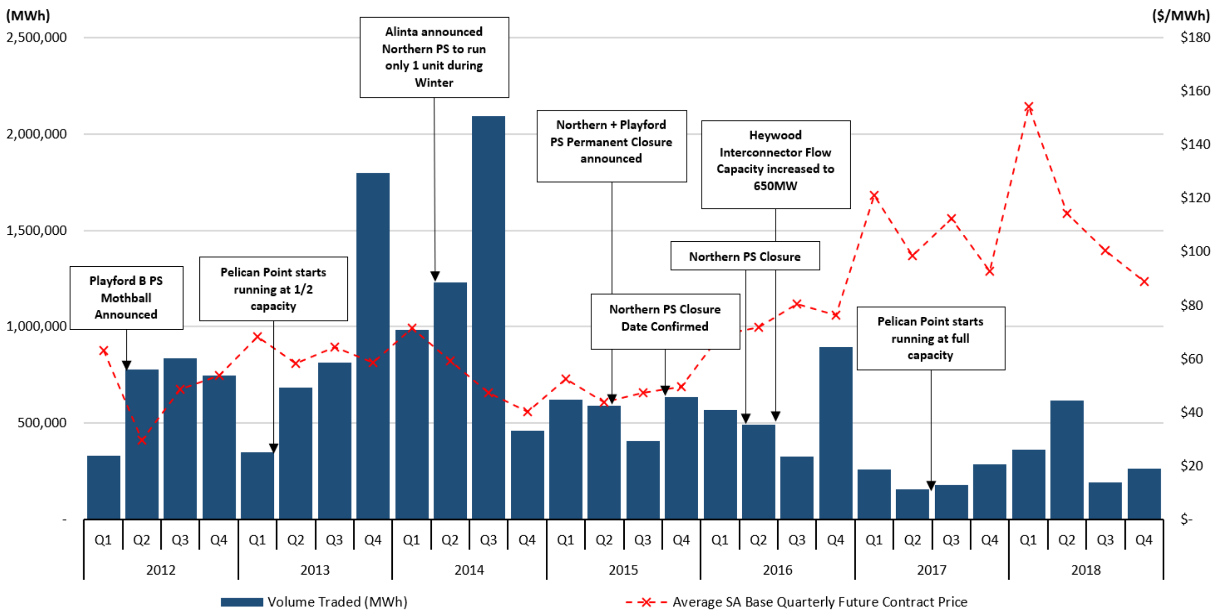
4.3 Events That Have Impacting Liquidity in SA

- *It is clear that the level of hedging volume is impacted by the amount of conventional generation is available in SA.*
- *We note that as the market expects supply to reduce there is generally increased demand for swaps, so that counterparties can have hedges in place to mitigate against potential increases in spot prices.*
- *As Northern Power Station and Pelican Point Power Station reduced output to one unit each, subsequent quarterly base swaps traded at reduced volumes and when Northern announced its total closure the price of quarterly swaps started to increase materially whilst the volumes traded decreased.*
- *SA now is trading its lowest volumes of quarterly swaps since 2012 and the price of these swaps have increased by up to 100% across annual periods.*
- *What the information shows is that SA is sensitive to both demand and supply of hedges and the underlying operating cost of what generation plant is supplying the hedge. Post Northern coming out of the generation mix, the volume of quarterly hedges decreased, however there is also a price impact that is likely impacted by both the demand/supply of hedges and since 2016 the gas costs that drive the cost of producing electricity from GPG has doubled.*

On 9 May 2016, the 546MW Northern Power Station at Port Augusta was permanently shut down. Combined with the retirement of the 240MW Playford Power Station, this removed the lowest cost form of baseload generator from the SA market. The Pelican Point Power Station was originally designed to operate as a baseload power station, however the changing electricity market conditions and rising gas prices have seen the plant change its operating regime and reducing its output. The remaining conventional generation is mid-merit (load following) or peaking generation. The remaining baseload generation is gas fired and represents an expensive form of generation given the increase in domestic gas prices.

These events led to further reduction in the liquidity of forward contracts and also meant that a greater premium was being extracted for hedging contracts. Over the course of the last five years the volume of forward contracts has nearly halved whereas the price for these contracts has more than doubled for certain quarters. This can be observed in the chart below.

Figure 16 Volume of Base Quarterly Futures Traded on the ASX for SA (2012-2018)



Source: CQ Partners using AEMO and ASX Data

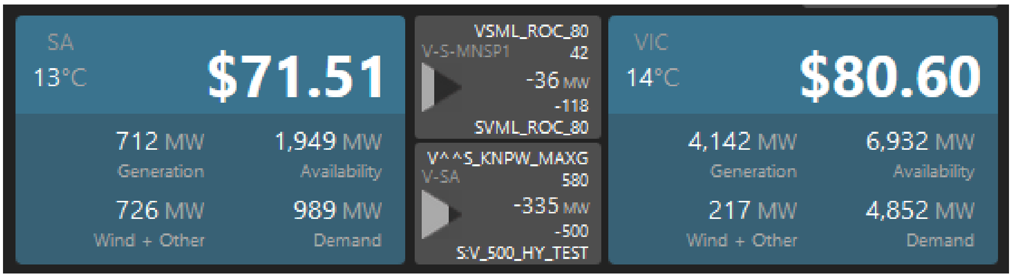
5 Use of Inter-Regional Settlements Residue (IRSR)

- *Improved interconnection will assist in the ability of participants to hedge inter regionally.*
- *As the SA hedge volumes became more illiquid over time, SA participants started to utilise inter regional hedges to greater effect. The purchase of IRSR units to effectively firm up Victorian swaps into SA has been used with reasonable success for some time.*
- *Buyers of Victorian hedges and IRSR units now have greater reliance on the interconnector not being constrained and as a result are placing less value on the basis risk that was priced prior to the Heywood Interconnector upgrade. This can be seen in Figure 19 of the report, which shows a convergence of pricing between the SA and Vic hedge once the cost of the SRA is taken into account.*
- *The utilisation of the Heywood Interconnector has provided SA customers and retailers with an alternative to just SA based hedges, creating better liquidity.*
- *It is expected that the SA - NSW Interconnector will also allow a reasonable level of inter-regional hedging between SA and NSW, creating greater efficiencies in managing risk. This will likely improve the ability of participants to manage risk in a market where hedging liquidity is shrinking.*

5.1 What is IRSR?

Inter-Regional Settlements Residue (IRSR) is the result of price differences between regions through electrical power flows via regulated interconnectors. IRSR is positive when energy is flowing from a lower priced region to a higher priced region and negative when energy flows to a lower priced region. When regulated interconnectors are unconstrained, the price differential between 2 adjacent regions is minimal and reflects the cost of inter-regional transmission losses. The figure below shows energy flows from SA (lower priced region) to Victoria (higher priced region) via the Murraylink and Heywood interconnectors with the price differential of $9.09/MWh reflecting the cost of losses between SA and Victoria.

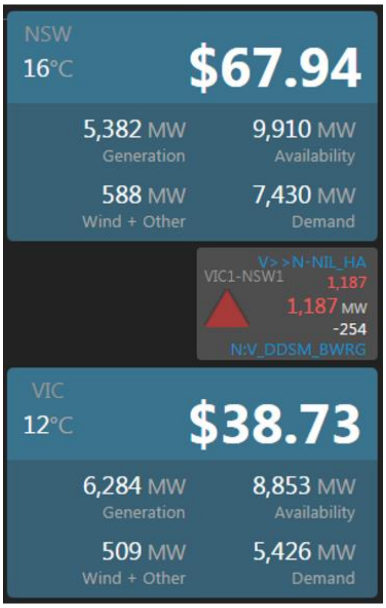
Figure 17 Interregional Transfer – Below Capacity



Source: NEO Mobile

Conversely, the price differential can be much higher when interconnector flow is constrained, as each region sets price independently of the other. The figure below shows energy flows from Victoria (lower priced region) to NSW (higher priced region) via the Victoria to NSW interconnector which is constrained. The price differential of $29.21/MWh represents the ability of NSW generators being able to set the marginal cost of electricity in that region independent of the importing region's price.

Figure 18 Interregional Transfer – At Capacity



Source: NEO Mobile

IRSR represents a pool of surplus funds that AEMO receives (i.e. from loads purchasing electricity in Victoria at $80.60/MWh compared to the payment of generators in SA at $71.51/MWh).

AEMO operates a Settlements Residue Auction (SRA process allowing registered parties to bid in advance for a share of the IRSR pool for specific interconnectors). The SRA units represent a proportional entitlement of interconnector nominal capacity to the accumulated IRSR for a given interconnector. In the case of the Victoria to SA interconnector, nominal capacity is currently 700MW (SA to Victoria flows) and 820MW (Victoria to SA flows).

The auction process consists of 12 auctions for SRA units in equal tranches conducted in advance for each quarter covering a period of 3 years, with unsold units from a previous auction rolled over to subsequent auctions. Participants submit bids electronically which comprise a number of units and a price with the resulting price set based on the lowest bid for available units. Successful bidders receive SRA unit distributions weekly approximately 20 business days after the end of each weekly billing period.

5.2 How are SRA Units Used?

The SRA process provides an ability to “firm” up hedges bought in an adjoining region into the importing region. This is an alternative to sourcing hedges locally, and for SA it has worked well due to the liquidity issues that has been experienced in the forward contracts market. For example, a retailer wishing to purchase a swap in SA to service its SA customers could purchase a Victorian swap, then “firm up” through the purchase of Victoria to SA SRA units. A retailer would generally undertake this process where there is low supply of hedges in SA and/or where the retailer is banking on purchasing a hedge via the SRA process at a lower price. For example, a calendar swap in SA may be trading at $110/MWh for 2020, while the retailer may be able to purchase a calendar 2020 swap in Victoria for $80/MWh hoping access to a SA to Victoria SRA unit at or below $30/MWh.

5.3 Risks Associated with SRA Units

There is a however a degree of basis risk associated with SRA units across interconnectors. SRA units are purchased against the interconnector notional capacity, which means that any derating of the capacity of the interconnector at times of high price differential devalues each SRA unit. Derating can occur due to planned maintenance, equipment thermal or stability limitations and operational constraints in the dispatch process. Since the upgrade of the Heywood interconnector, it has been considered to be more reliable from an outage perspective and parties appear more willing to bid on the SRA's to the difference between the Victorian hedge and SA hedge price. This can be seen in figure 19, which shows a convergence of pricing between the regions after accounting for the cost of the SRA.

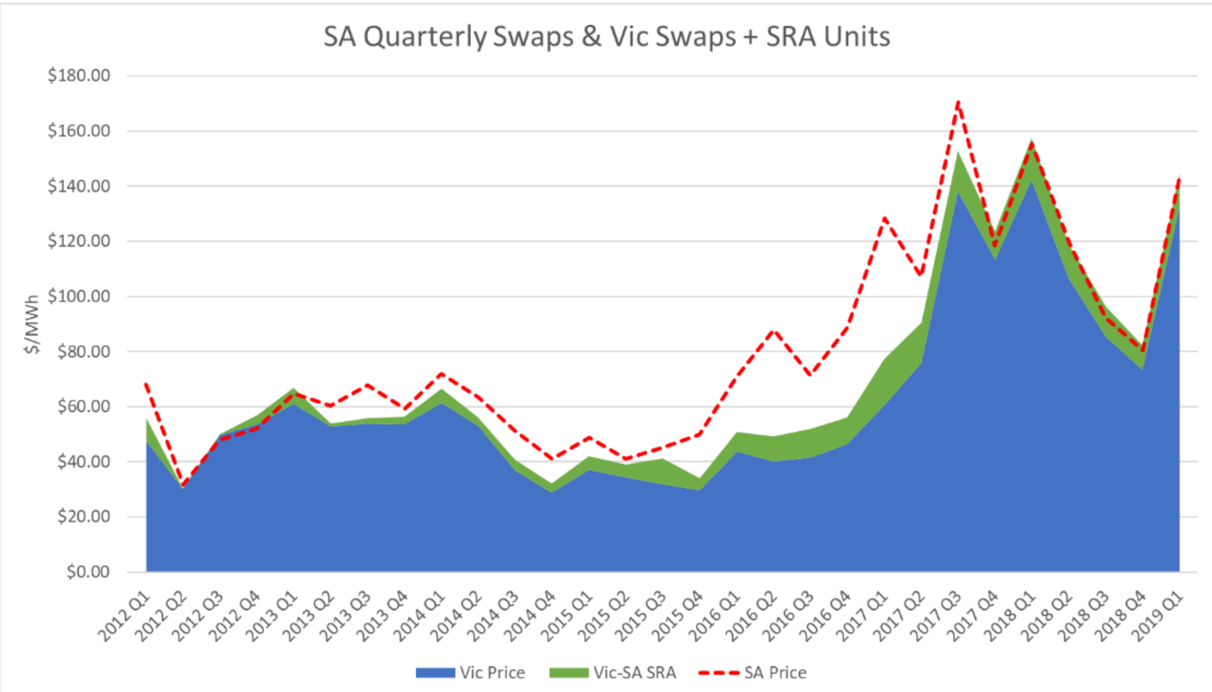
5.4 Outcome of SA-Vic SRAs to Hedge in SA

We have undertaken analysis comparing the ASX prices for SA quarterly flat (all hours) swaps with purchasing an equivalent Victorian swap to hedge load in SA through the use of a Victoria to SA SRA unit. The benefit sought is to achieve a lower hedge price through a lower Victoria hedge + SRA unit price in $/MWh when compared to a SA hedge.

The graph below compares the purchase of SA quarterly flat swaps with purchasing the equivalent Victoria swaps plus Victoria to SA SRA units. It is clear the price spread between SA swaps and Victorian swaps + SRA units was much greater between 2013 to Q3 2017. This is symptomatic of a more liquid market in SA where purchasers had the option of purchasing SA swaps at reasonable prices and volumes. As the generation supply and liquidity tightened in SA with the closure of Playford PS and Northern PS, demand for Victorian swaps and Victoria to SA SRA units has increased, resulting in the hedge options converging with minimal or no benefit to SA customers seeking to hedge in Victoria.

The convergence of SA hedge prices with the use of Victoria to SA SRA units could also be symptomatic of a market that views SRA units as a reliable hedge source which assumes interconnector flows are unlikely to be constrained, providing full value for the SRA units.

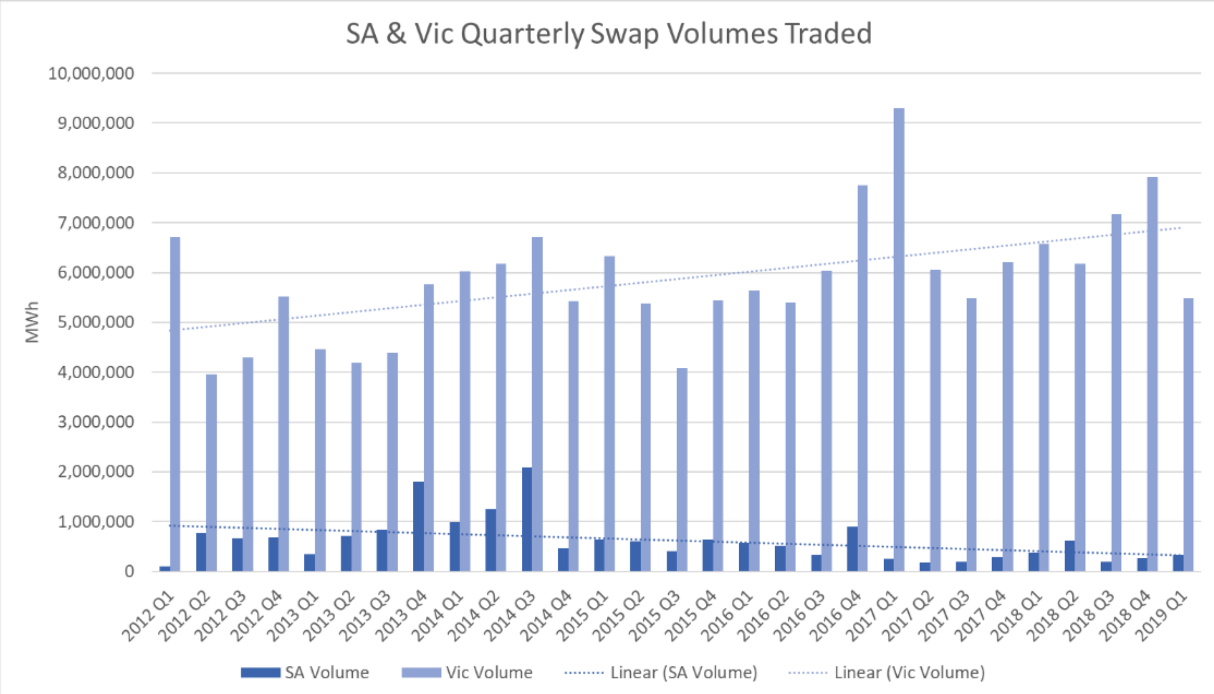
Figure 19 SA Quarterly Swaps & Vic Swaps + SRA Units



Source: CQ Partners using ASX & AEMO data

The chart below shows the reduction in volumes traded in SA and corresponding increase in demand for Victorian swaps aligning with the convergence in pricing between SA swaps and Victorian swaps + SRA units. It is likely that we would see a fully subscribed SRA auction process on the SA to NSW Interconnector like it is on the SA-Vic Heywood Interconnector, illustration an efficient inter-regional hedge mechanism.

Figure 20 Vic and SA Quarterly Swaps Traded



Source: CQ Partners using ASX data

The viability of settlements residue must be a consideration for SA - NSW flows. During periods where SA would be a net exporter to NSW, then SRA units between NSW and SA are unlikely to address liquidity issues in SA. However, as SRA's are directional, when SA is exporting to NSW, the NSW spot price is expected to be higher than that in SA and as a result the hedges bought in NSW will still provide a payout for those in SA.

The ACIL Allen report titled "*South Australia New South Wales Interconnector – Updated Analysis of Potential Impact on Electricity Prices and Assessment of Broader Economic Benefits* (figure 3.4) indicates spot prices in SA will be higher than NSW in all years between 2020 and 2030. It could be assumed under this modelling that net interconnector flows will be predominantly from NSW to SA (i.e. lower to higher priced region) and hence there will be adequate settlements residue for SA customers seeking to hedge via NSW forward contracts.

6 Firming Products Available

- *The market is starting to deliver new derivative structures to solve hedge liquidity and lack of PPA structures to underwrite renewable projects.*
- *These structures effectively provide renewable projects with a level of financial firmness that guarantees a revenue stream over a number of years. These structures can underwrite merchant positions or incorporate off-take positions.*
- *What these products provide is a benefit to the market in delivering projects that may not reach financial close without a PPA being entered into.*
- *The NEM generally will look more at these products to deliver against the long list of proposed renewable wind and solar projects that are awaiting debt and equity funding.*
- *The market needs these new and innovative structures to be able to deliver enough projects to match the retirement schedule expected from the exit of coal fired generation and some GPG plant.*

This section discusses the firming up of intermittent renewable generation facilities. Normally a solar PV generator or wind farm generate electricity on an intermittent basis. The issue with this is that those buying the electricity are not guaranteed energy when they are using it (in the case of a large industrial user) or selling it on (in the case of a retailer). As the pipeline of projects in the renewable space is so large, the differentiator is to try to offer the electricity as 'firm', that is selling a fixed swap from the generator that can be relied up by the off-taker.

Retailers and customers are increasingly aware that the underlying spot price is becoming more volatile and is increasing in terms of average costs. So, the need to cover as much of your load as a consumer from a renewable source is important. The issue for intermittent plant is that the hedge market (both swaps and caps) are too expensive and the liquidity issues faced in SA often makes the project uncompetitive from a pricing perspective to the off-taker once the cost of hedging is accounted for. This then leaves the project to either go merchant and rely solely on spot revenue, to enter into as generated or non-firm off-take agreements at a discount or look to alternative structures that replicate a power purchase agreement (PPA) with a retailer or large customer.

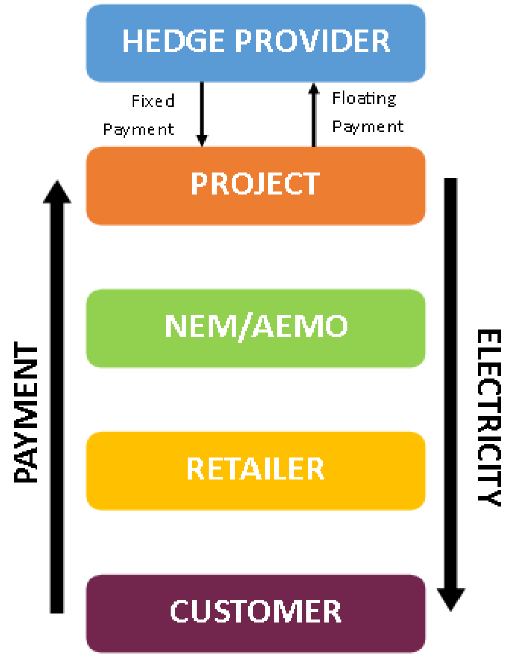
The need for a PPA or electricity off-take agreement is that for most renewable generation facilities, this is what is needed to attract sufficient debt and equity to the project for it to become financially viable.

The firming products discussed in this section are not a direct solution in addressing illiquidity in SA, but rather seek to facilitate agreements between suppliers and purchasers of energy for renewable projects. Therefore, these products should be viewed as a way to alleviate, not replace, the need for conventional underlying hedges in the market.

The following section describes an alternative to using traditional futures contracts and utilising proxy revenue swaps that are underwritten by re-insurance companies that are prepared to take a position in the NEM by offering the renewable project a fixed revenue payment that has a CFD based upon the floating price, which is the generation profile of the generation facility by the spot price.

6.1 Proxy Revenue Swap

Figure 21 Proxy Revenue Swap Structure



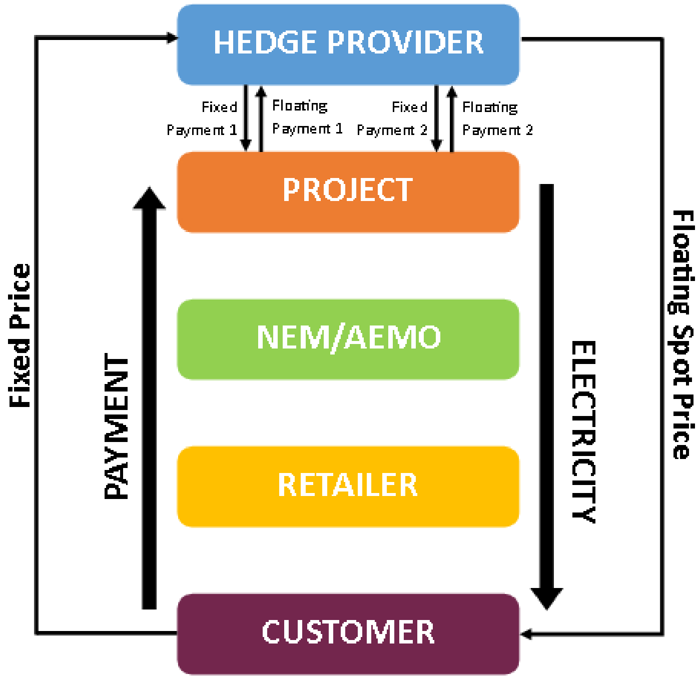
Source: CQ Partners

A Proxy Revenue Swap (PRS) is a structure that mitigates risks associated with volatile pricing in the energy market and variable generation due to weather conditions (wind, solar irradiance) by guaranteeing a fixed revenue for a project's output. A PRS guarantees the project a fixed level of annual revenue through the hedge provider who in turn absorbs associated risk (volume, price and shape). This form of hedge effectively addresses the instability in revenue resulting from fluctuations in the spot price and the unpredictable wind or solar generation.

A PRS is settled as a contract for difference (CFD) based upon the variance between the annual proxy revenue strike (fixed payment) and the floating revenue received by the project on a proxy generation basis. Under a PRS, the project receives a payment from the hedge provider when the proxy revenue is below the agreed fixed revenue. Conversely, when the proxy revenue exceeds the fixed revenue, the project is required to make a CFD payment to the hedge provider.

6.2 Proxy Revenue Swap and Balance of Hedge

Figure 22 Proxy Revenue Swap with Balance of Hedge Structure



Source: CQ Partners

A Balance of Hedge (BOH) utilises the same structure as a PRS but a BOH reflects the notional quantity of a Fixed Volume Swap (FVS) into the fixed revenue to the project.

The diagram above depicts a hedging structure that incorporates both a Proxy Revenue Swap (PRS) and a Balance of Hedge (BOH) with a Fixed Volume Swap (FVS) sold directly to the customer. With this combined strategy, the customer has two options; transact with a retailer who provides the pool price as a pass-through service or be a market participant in their own right and face AEMO. In terms of settlement, the customer can either transact with the hedge provider or directly with the project who would then proceed to pass the fixed and floating payments through. There is no difference between the two approaches in relation to cash flows only who receives/provides credit support, if required.

The PRS and BOH structures would work well with the ACCC recommendation to the Federal Government to establish a guaranteed offtake at a fixed price for years 6-15 of the project. Ultimately, the market is already starting to provide solutions as to how best to commercialise renewable projects that are finding it difficult to obtain suitable PPA or off-take agreements required by debt and equity providers to the project.

7 Outlook for Existing Generation

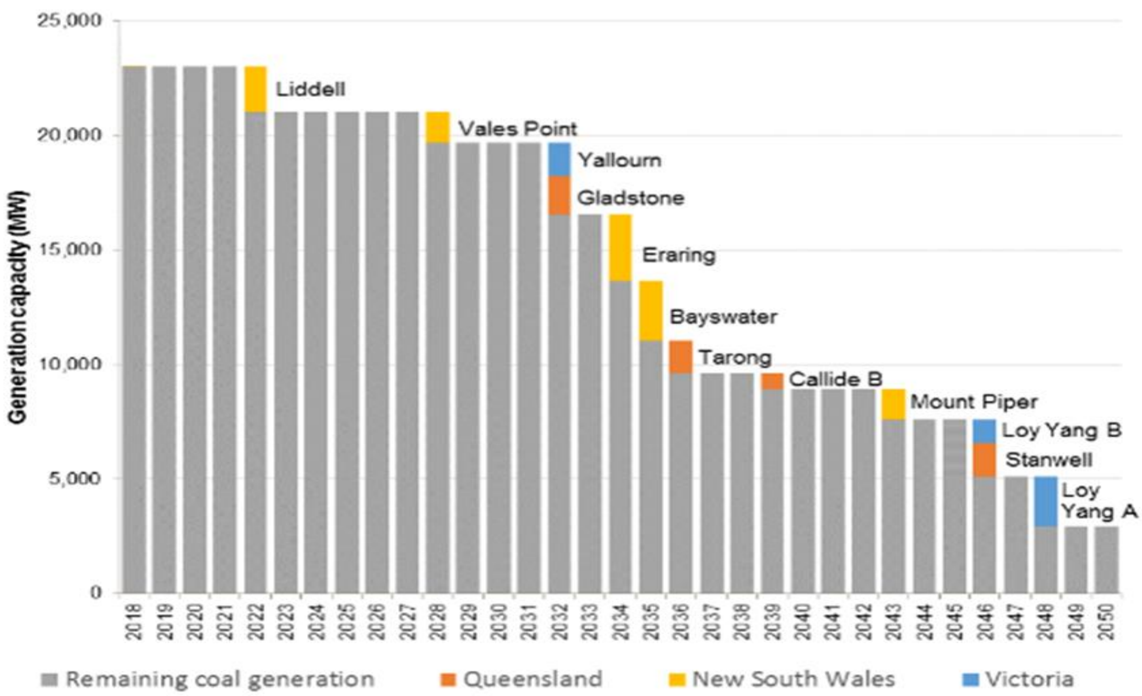
- *The NEM is forecasting a significant number of coal fired generators to retire at the end of economic life. This will create a need for new generation investment and the key is increased levels of wind and solar plus utility scale storage.*
- *The level of wind and solar does not provide appropriate hedging capability due to its intermittent nature and therefore the need for storage at scale and also for continued flexible gas generation is needed to provide participants with a mechanism to reduce price volatility, when intermittent generation is not available.*
- *The removal of GPG in the short term and prior to the SA-NSW interconnector being built creates a risk for SA that hedging liquidity will be extremely poor, putting at risk the ability of parties to manage risk appropriately.*
- *Barker Inlet Power Station should assist in the loss of TIPS A.*
- *The SA-NSW along with the SA-Vic interconnector will allow greater inter regional hedging, which should improve liquidity after it is built.*
- *What is evident however is that the market either needs to resolve the cost impost of high gas prices on electricity prices or leapfrog gas infrastructure in favour of low-cost renewable generation facilities.*

Below is a summary and discussion of the analysis produced by AEMO as part of their ISP.

7.1 AEMO - Integrated System Plan 2018

AEMO's 2018 ISP projects that, with no developments in the supply side of the electricity market via an upgraded transmission network, current conventional thermal generators will retire at their announced retirement dates or at a time based upon the technical life age of the plant. Figure 23 below illustrates these retirements out to 2050. This is in addition to the expectation that by 2025 the main conventional gas generators (1,462MW) will be retired post the interconnector.

Figure 23 NEM Coal-Fired Generation Fleet Operating Life



Source: AEMO Integrated System Plan 2018

The combination of about 1,462MW of capacity from conventional plant retiring in SA in combination with Liddell Power Station (2,000MW) in the short term, reduces conventional generation across both regions by about 2,450MW. No doubt this will have an impact on hedging liquidity across both markets, however the SA-NSW Interconnector is not a reason for this withdrawal of plant and will most likely allow better hedging across these regions.

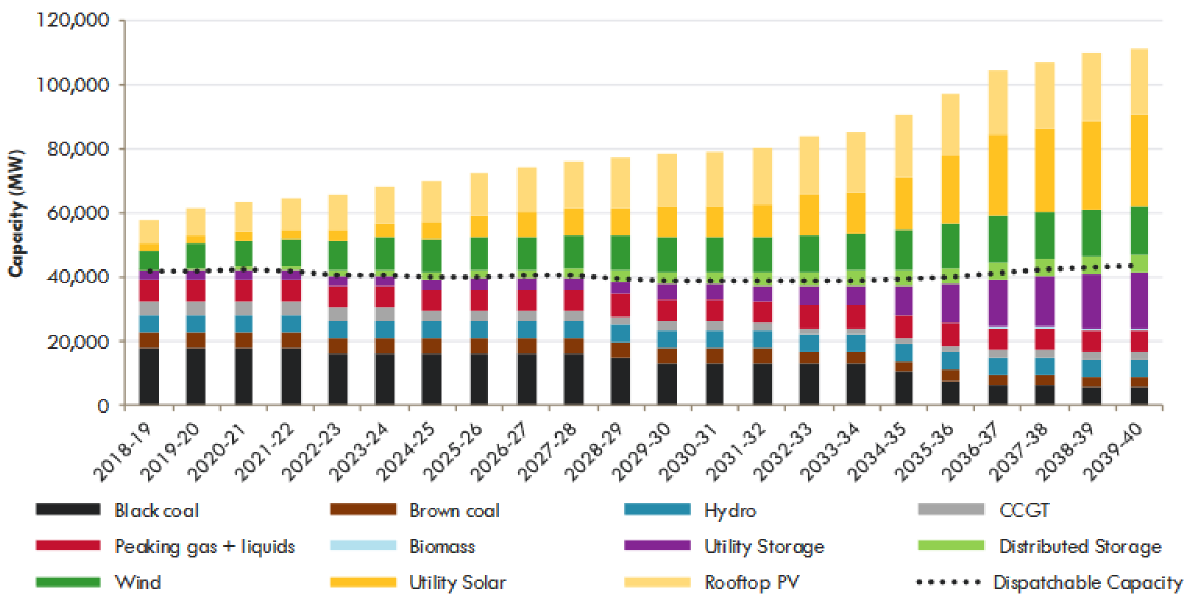
In the longer term there is a much greater impact on the market as coal fired generation starts to retire in volume (see figure above). Again, these retirements are caused by end of economic life of these plants and a transition in the market to low carbon intensive generation plant. The market will need to adapt with not only wind and solar, but other forms of generation that provides better network capability.

Following the development of the Australia's transmission network, including the SA - NSW Interconnector, AEMO's ISP forecasts NEM will transition from a system dependent upon high utilisation, low cost conventional thermal generation to a mix dominated by zero marginal cost variable renewable generation. To analyse the potential material impact of increased transmission development on conventional thermal generation retirements in the NEM, AEMO developed a number of different scenarios designed with a range of variations around operational grid demand, grid-scale generation capital cost reductions, economic growth, population, levels of consumer engagement and the deployment of new technologies. The modelling covered a period of 20 years, out to 2040.

7.1.1 Neutral Scenario

The Neutral Scenario assumes a range of central (mid-point) projections of economic growth, future demand and fuel costs. This scenario adopts the approach of least cost generation expansion to meet consumer needs within the confines of policy, demand and market settings. It allows for economic based retirements where these lead to reductions in total system costs. The forecasted generation capacity from 2018 to 2040 for the Neutral Scenario is shown in the chart below.

Figure 24 Forecast NEM Generation Capacity - Neutral Case



Source: AEMO Integrated System Plan 2018

What is clear from the forecast is that dispatchable storage is going to be required as coal and gas capacity reduces through the forecast period. The uptake of utility storage will be valuable from a hedging perspective as it will provide participants with the ability to manage risk through physical discharge of energy when required. It will be interesting to see whether this generation mix will provide a lower overall cost of electricity as compared with the current generation mix.

It is likely that reducing the utilisation of high cost gas generation in favour of low-cost renewable generation in addition to utility scale storage will provide a better long-term outcome from a pricing perspective.

7.1.2 ISP Retirement Summary

AEMO also ran a fast and slow change scenario. In each scenario, the majority of Australia's existing coal fired power stations are assumed to reach the end of their technical life (50 years of age), by 2040 and will need to be replaced by other sources of generation. Only three stations are projected to close within the first decade, Liddell (2022) and Vales Point (2028) in NSW, and Gladstone (2029) in Queensland. A reduction in CCGT and steam generation capacity can also be seen during this time period which can be attributed to SA's conventional power stations shutting down their operations.

The ISP predicts that by 2025, South Australia will have no CCGT with the remaining gas fleet comprising OCGT or gas peaking plant. The reasoning behind these retirements is that following the construction of the SA-NSW Interconnector, SA's electricity demands could be met through the lower cost supply in SA or via interconnection from the east coast.

The modelling also considers the impact that early retirement of conventional generation would have upon the NEM's base load capacity. AEMO adopts the view that developments in the transmission network (e.g. SA-NSW Interconnector) should be considered as pre-emptive measures for increasing the resilience of the power system.

Another consideration of the ISP is the need for conventional thermal generators to shift from the baseload generation to a more flexible synchronous profile. This would assist in the management of the variability and oversupply associated with renewable wind and solar generation. The use of gas power generation (GPG), in particular, is projected to evolve to a more complementary role to these variable renewable energy resources. Whilst AEMO has not forecast any new developments in GPG, it is feasible that the operating life of some CCGT plants may extend longer than projected in this new role. One of the issues with gas fired generators running more flexibly is that the purchase of both gas commodity and haulage will need to become more focussed on intermittent utilisation as opposed to trying to contract for flat volume and haulage.

8 Future SA Forward Contract Liquidity

- *It's clear that from AEMO's ISP and also the list of proposed and committed projects in SA that there will be a significant build of generation projects that will ultimately well exceed the level of underlying demand.*
- *With maximum demand sitting at about 3,000MW in SA and a build capacity that will exceed this by a substantial volume, when adding interconnection to both Victoria and NSW, the future expectations is for a dampening of spot prices. Noting that hedging is most valuable in a volatile market with underlying high prices, there is an expectation that as gas GPG is increasingly replaced in the merit order with renewable generation, the overall cost of electricity to consumers should reduce.*
- *Interconnection of markets will assist in the sharing of renewable resources across regions, which should aid in the reduction of spot price volatility and prices, ultimately aiding the need for hedging instruments.*

The previous sections of this report focussed on the current and historical levels of liquidity in the SA forward contracts market, the contributing factors for decreased liquidity in SA and the forecast retirements occurring for generation across the NEM. This section will build on that analysis in order to assess the likely level of liquidity in the SA forward market in future.

8.1 New Entrant Generation

The previous section detailed the expected and forecast retirements for generation assets in both SA and NSW based on announcements from owner/operators and from modelling performed by AEMO . Equally significant to the liquidity of SA's forward market is the addition of new generation infrastructure. The table below summarises the information that AEMO has published.

Table 1 Summary of Generation Withdrawals, Commitments and Proposals

Status	Gas	Solar*	Wind	Water*	Biomass	Battery Storage	Other	Total
Existing	3,141	122	1,809	4	20	130	145	**5,371**
Announced Withdrawal	480	0	0	0	0	0	0	**480**
Existing less Announced Withdrawal	2,661	122	1,809	4	20	130	145	**4,891**
Committed	210	218	251	0	0	0	0	**679**
Proposed	669	2,388	3,330	755	15	488	30	**7,674**

Source: Regional Generation Information Page- SA, AEMO, 02 November 2018

Coinciding with the retirement of the TIPS A Power Station, AGL has committed to the construction of Barker Inlet Power Station, a new 210MW gas-fired peaking plant, with commissioning to commence in the first quarter of 2019 and full capacity available by quarter 3 2019. This power station is expected to permanently replace 2 of the 4 units at TIPS A Power Station.

In addition to Barker Inlet, there is an additional 469MW of renewable generation capacity committed to being completed in SA. All of this committed generation is expected to be at full capacity before the end of 2019.

Beyond the currently committed generation projects, a further 7,674MW capacity of generation is presently being proposed for construction in SA. 2,388MW of these are solar projects, 755MW are hydro, 3,258MW are wind farms and 624MW are natural gas.

8.2 New Entrant Storage

There are a number of publicly announced storage projects in SA comprising both pumped hydro and battery storage with capacities up to 300MW and storage between 4 and 8 hours. At present, these projects are seeking commercial arrangements for offtakes through mechanisms such as proxy revenue swaps and direct PPA's with retailers, aggregators and customers. As a number of these projects will rely on debt funding, off-takes will need to be established in an environment where customers are reticent to commit beyond 5 years.

These projects have several revenue streams including the provision of firming and hedge (caps & swaps) products to the SA market. Other revenue streams such as FCAS and spot arbitrage are also considerations and whilst the provision of firming products through these projects could address liquidity in the SA market into the future, these projects are not at a stage where they can be considered committed.

Table 2 New SA Energy Storage Projects

Project	Nameplate Capacity	Owner	Technology	Status
Cultana Pumped Hydro Project	225MW (8 hours storage)	Energy Australia	Pumped Hydro	Feasibility report completed. Undergoing technical design with final investment decision, late 2019.
Goat Hill	230MW (8 hours storage)	Altura	Pumped Hydro	Development approval given May 2018, final investment decision late 2018 and operational early 2020.
Highbury	300MW (4.5 hours storage)	Tilt Renewables	Pumped Hydro	Pre-feasibility with SA Government banning housing on the site.
Kingfisher Solar Storage	100MW (4 hours storage)	Lyon Group	Battery	Waiting final investment decision.
Riverland Solar Storage	100MW (4 hours storage)	Lyon Group	Battery	Development application approved. Pending connection agreement. Waiting final investment decision.

Source: CQ Partners using AEMO Data

Snowy Hydro's recent announcement of 800MW of firm energy to be provided through a combination of renewable projects in NSW and Victoria with firming through its hydro generation assets provides positive indications the above SA projects could potentially contribute to liquidity in SA. Snowy Hydro claim the potential to offer firm energy contracts at under $70/MWh over a period of 15 years.

The potential for the above announced SA storage projects to alleviate liquidity issues in SA is primarily dependant on these projects establishing offtakes with customers to make these projects viable.

9 Impact of Large-Scale Storage Projects

- *Snowy 2 is expected to provide significant benefits to the market (we have not assessed this on a net benefits case), including the provision of network support such as inertia, FCAS and acting as a load during excess renewable generation.*

9.1 Snowy 2.0

Snowy 2.0 project is a pumped hydro storage project providing 2GW of power with 175 hours of energy storage at 2GW. The project will expand the existing Snow Hydro scheme to a capacity of 5.7GW.

The Snowy 2.0 project can act as a load by pumping water to be stored for generation dispatch according to market needs. Essentially Snowy 2.0 acts like a large battery facilitating the consumption of energy during lower priced/lower demand trading intervals and as a generator during high price/high demand periods. Snowy 2.0 will have a cycle efficiency of 76% such that to generate for 8 hours it would need to pump for 10.5 hours.

The project will require strengthening of the transmission network between Snowy 2.0 and Bannaby in NSW and is likely to have a marginal loss factor of 1.0 given the equivalent power flows each way along this section of the transmission network.

Figure 25 Location of Snowy 2.0 Connection

Source: Snowy Hydro

There are several benefits proposed by the Snowy 2.0 project given the project's scale and operation as an energy storage plant and are listed below:

- Provision of Frequency Control Ancillary Services (FCAS);
- Reducing FCAS market prices;
- Provision of inertia (spinning reserve);
- Absorbing excess renewable energy by acting as a load (pumping);
- Providing energy during shortfalls to meet demand (generating);

- Reducing spot price volatility by smoothing the supply demand balance during periods of intermittent generation;
- Allowing baseload plant (coal & gas) to operate in a more stable load through not being required to ramp up/down during periods of intermittent generation;
- Provision of firming products to the market;
- Increased interconnection with Victoria (would require interconnector limit to be expanded to 1,300MW) and SA (assuming SA-NSW Interconnector constructed).

The realisation of the above benefits is dependent upon upgrades to the existing transmission network in NSW including Snowylink North (the Snowy 2.0 to Bannaby section) and Kerang Link to facilitate increased flows between NSW and Victoria to coincide with the commissioning of Snowy 2.0 and the retirement of Liddell.

The following sections expand on the Snowy 2.0 impacts relevant to liquidity and price outcomes.

9.2 Reduced Operating Costs for Baseload Plant

Baseload generators such as coal and gas incur increased operating costs through having to ramp up/down to cater for fluctuations in demand and in particular, renewable generation but ultimately have lower utilisation as they ultimately get displaced more often by lower cost intermittent plant. This change in their operations means that they have fewer running hours in which to recover their variable and fixed costs.

The vast increase in renewable projects to be deployed in the NEM in the short-term will only further increase operating costs for these generators leading to more volatile spot prices but most likely with an overall reduction in average spot prices as low-cost plant gets dispatched first.

Snowy 2.0 would reduce the need for these generators to ramp down during periods of high renewable generation/low demand by pumping (acting as a load). Conversely, Snowy 2.0 generating would reduce the requirement for these generators to ramp up during periods of low renewable generation & high demand. It is likely these benefits to be most prevalent in NSW although both SA and Victoria which have periods where NSW generators set prices in those regions will also benefit through reduced spot prices.

Modelling undertaken by Marsden Jacobs for Snowy 2.0 have indicated NSW to benefit from spot price reductions of between $7 and $20/MWh, assuming government renewable support beyond the LRET (Post 2030 Commitment). SA and Victoria have been modelled to receive more modest spot price reductions under the Post 2030 Commitment scenario.

9.3 Increased Firming

Snowy 2.0 will provide supply of firm energy to the market through its ability to flatten supply/demand fluctuations. Immediate beneficiaries will be NSW purchasers of firm energy and hedging products.

Through the SRA units process, SA purchasers could also benefit, although there is basis risk associated with potential interconnection constraints between NSW and SA in addition to the likely increase in demand for NSW caps and swaps potentially resulting in increased costs for SA customers to firm their energy needs and/or hedge their position. The basis risk however is expected to be minimal given the expected reliability of the interconnector.

Whilst there is the potential to provide access to increased firming for SA customers, the increase in dispatchable generation flowing from NSW to SA has the potential to displace SA baseload generators as is discussed above. This has the potential to further contribute to the retirement of baseload plant in SA. On balance however, it is expected that the Interconnector is unlikely to be the primary reason for conventional gas fired generators to exit the market. The high cost of natural gas will make inefficient gas generators less competitive as compared to renewable plant and more than likely they won't be able to compete on a commercial basis. The interconnector will in effect ensure that the most economic plant across regions are dispatched to meet prevailing demand conditions. It is expected that there will be a natural tipping point where renewable generation will replace gas generation in the merit order, regardless of interconnection.

Ultimately the expectation is that with the retirement of local SA conventional generation, those requiring hedging products will rely more heavily on interconnection from both Victoria and NSW to manage risk. The alternative in the medium term appears to be the introduction of utility scale storage that will act as a physical hedge and may even form a base for selling hedges.

9.4 Potential SA Projects

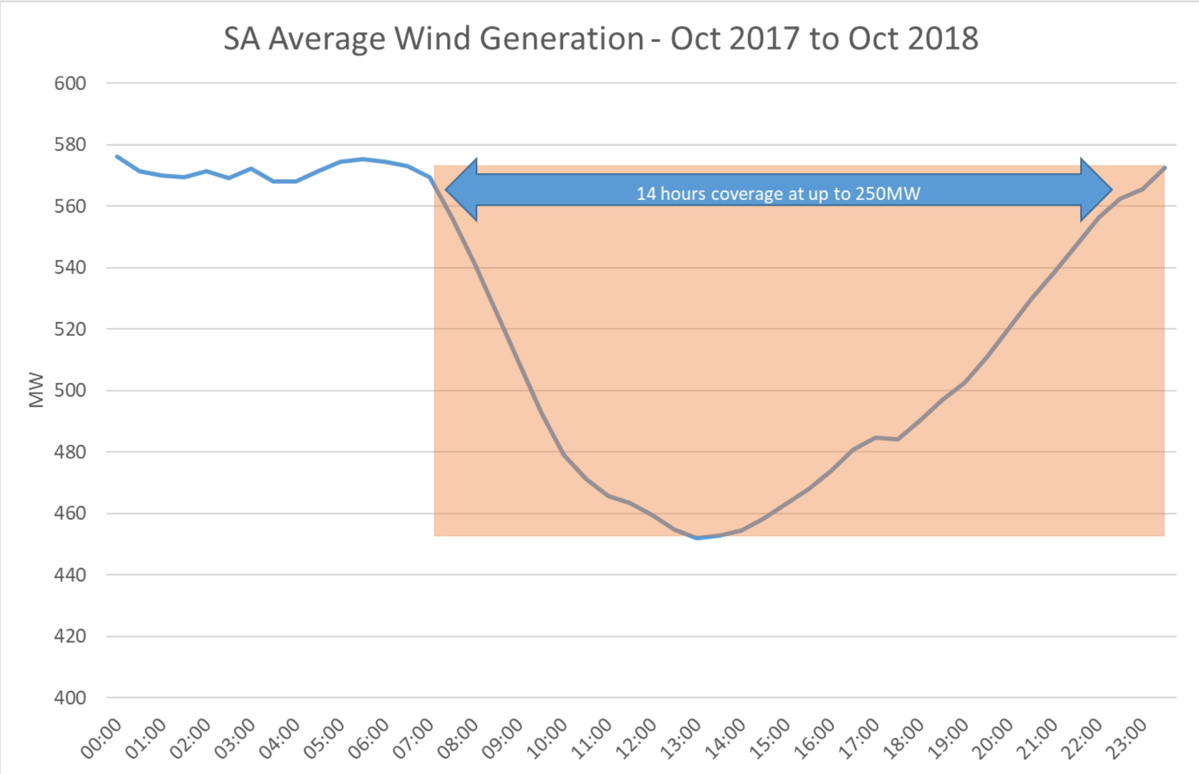
Increased interconnection between SA and other regions such as NSW has the potential to benefit new renewable projects that combine energy storage in SA.

The proposed Robertstown to Wagga Wagga option (C3) will allow increased access to low-cost, large-scale renewable projects developed in SA in close proximity to this transmission corridor. Large SA-based renewable projects providing additional renewable generation combined with storage will enhance grid stability, reduce FCAS prices whilst also providing valuable firm liquidity to both SA and NSW customers through storage plant.

As with increased interconnection with NSW, the presence of these large-scale projects combining storage are likely to displace existing baseload fossil generators in SA leading to early retirements.

The issue in providing energy storage is providing enough at the required scale to "firm up" SA renewable generation. Storage projects providing around 1 to 2 hours of storage would provide benefits to system security such as FCAS and inertia whilst also benefitting themselves through spot price arbitrage where high and low spot prices determine when a battery is best placed to discharge (high spot prices) and charge (low spot prices). To "firm up" renewable generation, particularly wind generation, of which represents a significant proportion of SA's installed generation capacity requires higher levels of storage as is illustrated in the chart below. The chart shows average SA wind generation for the October 2017 to October 2018 period and indicates, on average, coverage of falls in wind generation would require up to 14 hours of coverage at up to 250MW, representing over 2.5GWh of storage required.

Figure 26 SA Average Wind Generation Profile



Source: CQ Partners using AEMO Data

10 Impact of Increased Interconnection

10.1 Level of Inter Regional Trade across SA-NSW Interconnector

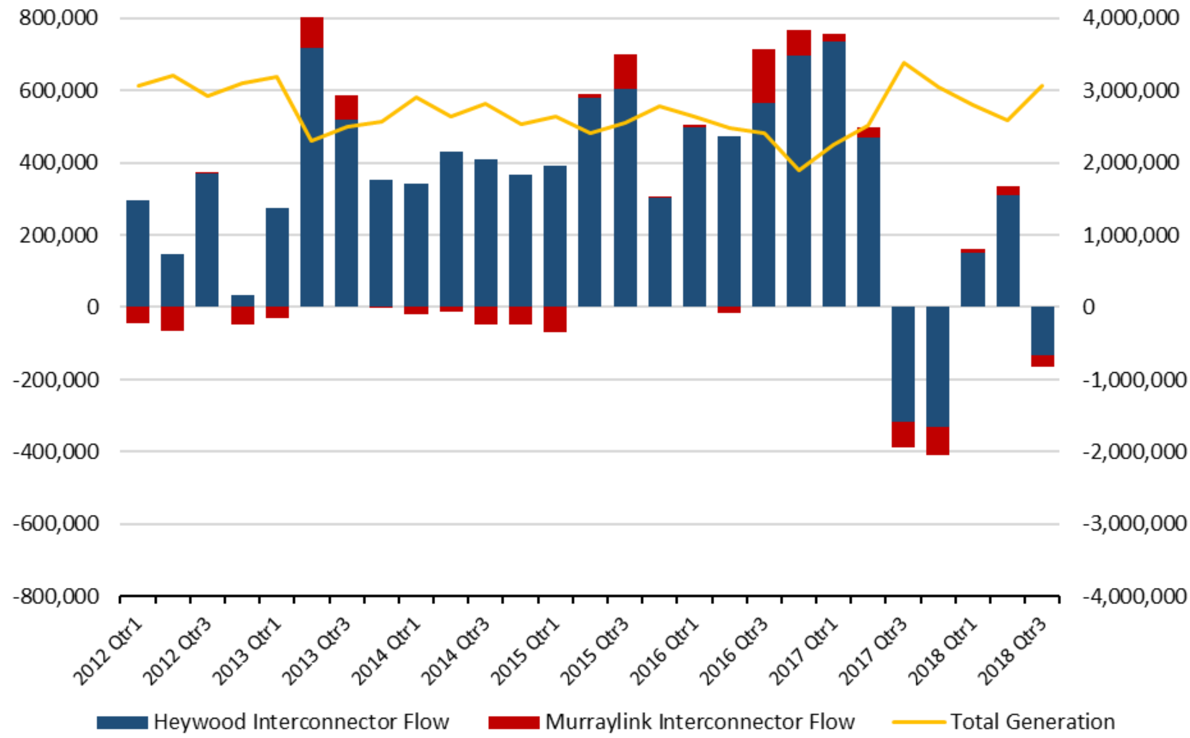
The level of inter-regional trade across an interconnector between SA and NSW will be highly dependent on several factors including the future demand, the number of generator retirements and the level of investment in new generation or storage infrastructure in each region.

According to the Electricity Statement of Opportunities published by AEMO in August of 2018, demand in SA is expected to remain flat (with a decreasing amount being sourced from the grid due to further rooftop PV investment) and in NSW will remain flat initially before increasing in the medium term.

Modelling from AEMO forecasts retirements and further investment in renewable generation assets in both NSW and SA.

SA has in recent times (Q3 and Q4 2017 and Q3 2018) been a significant net exporter to Victoria through both the Heywood and Murraylink interconnectors (see figure 27 below). Combined with flat to gradually decreasing demand and significant investment in renewable generation in SA, it is likely that SA-NSW Interconnector could be a net exporter of electricity from SA to NSW. Any reductions in the system strength requirements that currently constrain off generation from wind farms in SA would increase the likelihood of this occurring.

Figure 27 Imports & Exports across Heywood & Murraylink Interconnectors (2012-2018)



Source: CQ Partners using AEMO data

10.2 Impact on Liquidity in SA

- *White it could be argued there is potential for interconnection to accelerate retirement of baseload generation plant in SA, further compounding liquidity issues in SA before they are addressed, we consider this unlikely as other factors such as high gas prices, significant renewable build and reduction in average and minimum demand all point to lower utilisation of GFG and coal fired plant.*
- *The presence of increased interconnection between SA and NSW is likely to encourage investment in more renewable generation projects (not only in SA but also in NSW, further growth in utility scale storage projects and increase the sharing of low-cost generation resources between regions providing lower electricity costs to consumers.*
- *The ability to share low cost generation infrastructure between regions is also expected to reduce the level of spot price volatility in SA as linkages to Victoria and NSW brings with it greater diversity in generation mix. With lower electricity costs and less price volatility, there is also an expectation that the cost and need for traditional hedges will reduce (our expectation is that there will still be a need for hedging instruments or access to physical generation or storage to manage price risk, but as price volatility reduces so too does the cost of providing those risk mitigating mechanisms).*
- *We also note that the ability of regions to hedge inter-regionally will also be important and the SA - NSW and Heywood Interconnector will increasingly be important to facilitate the flow of lower cost electricity into other regions but will also assist participants to hedge risk as traditional sources of hedges exit the market.*
- *The utilisation of the Heywood Interconnector has provided SA customers and retailers with an alternative to just SA based hedges, creating better liquidity. It is expected that the SA - NSW Interconnector will also allow a reasonable level of inter-regional hedging between SA and NSW, creating greater efficiencies in managing risk. This will likely improve the ability of participants to manage risk in a market where hedging liquidity is shrinking.*
- *In essence, the market is evolving quickly with a rapidly growing renewable sector and increased levels of embedded generation and large-scale storage to enter the market. This transition in part is a result of lower emission technologies being preferred to conventional generation but also because coal plant is expected reach its end of economic life towards the middle of this century, with about 20,000MW expected to retire by 2050.*
    - *The transition has also been hampered by increased costs of natural gas, which has reduced the ability to utilise GFG plant as an interim fuel. Instead the market is leap frogging GFG and instead invested heavily in renewable generation and utility scale storage.*
    - *The utilisation of further interconnection between regions is expected to create better synergies between regions, where lower cost generation facilities are shared to provide improved pricing, less volatility and improve network stability.*
    - *Participants in SA will have access to the Heywood Interconnector, the future SA-NSW Interconnector to manage inter regional hedging, but improved risk management will also come from greater utilisation of embedded and large-scale storage to manage spot price risk.*
    - *The real risk the market has is that in the short term there may not be sufficient investment in alternative risk mitigation assets (such as storage) as conventional generation retires. The introduction of the SA-NSW Interconnector should however improve the ability for parties to manage risk by using inter regional settlement residues.*

White it could be argued there is a potential that additional interconnection could accelerate the retirement of conventional baseload plant in SA, which may reduce the level of hedging liquidity, we consider it more likely that gas fired generation plant, particularly those that are inefficient and have high heat rates, will not be competitive in the medium to long term as compared to low cost renewable generation. As a consequence, their exit from the market will likely occur regardless of whether interconnection occurs or not.

Increased interconnection will also provide greater access to interregional hedging options with access to utility scale storage of about 650MW (without Snowy 2) and about 230MW (with Snowy 2), up to 975MW of additional wind and solar (without Snowy 2) and 230MW (with Snowy 2).

Even though there is a potential for further withdrawal of GPG post the SA - NSW Interconnector, namely the withdrawal of Pelican Point and Osborne Power Stations of about 650MW, the addition of utility scale storage and interconnection will be positive developments to stemming the loss of hedging counterparties in SA.

Our expectation is that the market will utilise utility scale storage and embedded distributed storage in a way that effectively provides a physical hedge to spot price volatility. For example, a large customer could have exposure to the spot market and utilise battery storage to supply electricity when the spot price is high. This wouldn't be an optimum hedge for underlying high prices, but could act as a cap for short periods. However, the expectation is that as the development of low-cost wind, solar and storage solutions increase penetration across the market, the impact on prices will be downwards.

The ability to utilise both the Heywood Interconnector and the SA - NSW Interconnector for inter-regional hedging utilising settlement residue auction units and also local utility scale storage plus peaking GPG will assist in the ability of parties to manage spot price risk.

Both interconnectors will add over 1,300MW of inter-regional hedging capability between SA and Victoria and SA and NSW. Even though there is expected to be some basis risk due to the risk of interconnector outages, this is expected to be low given the double circuit configuration of both interconnectors.

11 Other Options

Any other potential options to support increased wholesale market liquidity in SA such as, but not limited to, the recommendations from the ACCC's Restoring Electricity Affordability and Australia's Competitive Advantage 2018 report:

11.1 ACCC – Restoring electricity affordability and Australia's Competitive Edge

The ACCC focuses on 4 key areas of reform in order to reduce energy prices to customers and within these 4 key areas are 56 recommendations.

The 4 key areas are:

- Boosting competition in generation and retail
- Lowering costs in networks, environmental schemes and retail
- Enhancing consumer experiences and outcomes and
- Improving business outcomes

The first key area that the ACCC considers is the current lack of competition in the generation sector. SA for example has about 75% of generation consolidated in the ownership of 3 market participants. To a degree, the horse has already bolted with this generation position and now the expected elevation in spot price outcomes have largely reflected increased gas costs which ultimately has been passed through to consumers.

Surely a consolidated generation sector will likely result in a less competitive wholesale spot price, but the inability of new entrant generators that have access to lower cost generation, via solar PV and wind to obtain PPA structures to underpin their investment has been the big obstacle in our opinion. The fact is that in SA for example, the 3 generators that hold about 75% of the generation capacity are also retailers in the same market. They have no interest in assisting new generation competition or retail competition and why should they. So, for one of these retailers to enter into a long term PPA that effectively introduces competition to its portfolio is unlikely. As a result, AGL, Origin and Engie have all looked to develop their own renewable generation facilities instead of increasing the number of generation counterparties.

The recent introduction of PRS and BOH financial structures to underpin new entrant renewable generation into the Australia has broken the need for incumbent gen-tailers to be involved in that decision-making process. As a result, the market is evolving past this point and resolving the impasse that exists in the market.

The specific recommendation surrounding generation that may influence the level of liquidity in the market includes:

1. Limiting market share of generators to 20% in any NEM region (other than for new capacity).

   This may be a moot point now as the level of expected retirements in the market is likely to change this dynamic over the medium term in any case. For example, AGL's current ownership structure in SA means that it has a 30% ownership of generation capacity. However, with the likely retirement of both TIPS A and B, this position will likely fall well below 20% even with Barker Inlet Power Station coming online.

2. Queensland Government should divide its generation assets into 3 portfolios'.

   Ironically Queensland used to have 3 generation businesses that were amalgamated into 2 generation businesses. Certainly, increasing generation competition from 2 major generators that are largely conventional coal or gas into 3 is likely to have a competitive impact on pricing. We do note however that the generation businesses are still owned by the Queensland Government.

3. AER to be given special investigative power.

   Already the AER has significant powers to investigate breaches of the National Electricity Rules, particularly as they relate to bidding in bad faith. We don't believe that generation businesses have been acting outside the NER or with the intent to manipulate the market. However, the concentration of assets and the increase in input costs (primarily gas costs) are likely to have a result of increased pricing.

4. Australian Government to underwrite renewable generation

   The ACCC recommends that the Australian Government underwrite renewable projects by offering long term off-take agreements from years 6-15. This will mean that the projects will still need to obtain some form of PPA or off-take for the first 5 years of the project. Noting earlier comments in this paper, with the huge list of renewable projects currently in the pipeline, there is not sufficient large customer and retail off-take agreements that are expected to be entered into for the first 5 years.

   As noted earlier, the market has subsequently been developing alternative arrangements such as the PRS and BOH products to assist in these projects reaching financial close. The PRS is usually a 5-year product and as a result the Australian Government providing a 10-year PPA is likely to assist a number of renewable projects to get to financial close.

   We note again that these PPA structures are not intended to replace the hedges that are currently provided to the market by conventional plant, but rather a mechanism to underpin the revenue stream of the project itself.

5. Demand side response

   We agree that demand side responses should be adequately compensated. One of the main issues that we find with demand side management is that industry ordinarily should not be asked to reduce their load if the energy market is operating efficiently. Industry after all is in the business of producing goods and there is a natural inclination to maximise output as efficiently as possible. Requesting industry to demand side manage means that they are having to make opportunity cost decisions which ultimately is not ideal for efficient production of goods and services.

We also note that the ACCC concedes that SA already has contract liquidity issues and sees the opaqueness of OTC markets as an issue to efficient contracting. The recommendation here is that the Australian Energy Market Commission (AEMC) creates a market making requirement on existing generators to offer to buy and sell a certain amount of electricity contracts each day. The issue with this is that some participants may not have any contracts to sell or a need to buy. AGL for example, going forward may be in a short position for hedges contracts without a TIPS A and B. Simply via Engie may also find itself in the same position. At some stage, without conventional generation present in SA, there will be no natural sellers of hedges. We don't think that a requirement like this will work in the short or long term.

Ultimately it may fall on governments to incentivise the building and contracting from utility scale storage (such as batteries and hydro). The SA Government has established the Grid Scale Storage Fund which seeks to incentivise grid-scale storage projects that improve system security, provide firming generation, improve supply to meet peak demand improvements to weaker network locations during a period of significant renewable generation deployment. The SA Government has allocated $50M to the fund which will help to address issues facing the SA market, although at a scale unlikely to have any material impact on the region's liquidity issues.

At present the capital cost of both are too high in Australia and in the absence of incentivising gas generators to stay competitive, there should be incentives to build storage to manage system reliability, FCAS and risk management contracts such as caps and swaps.

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