6 October 2016

The Chair
Australian Energy Markets Commission
PO Box A2449
Sydney South NSW 1235

Lodged online

Dear Mr Henderson

MEU Comments on System Security Market Frameworks Review

AEMC reference: EPR0053, ERC0208, ERC0211, ERC0214

The MEU welcomes the opportunity to provide its views on the AEMC consultation paper on System Security Market Frameworks Review. The MEU has been involved with the issues of supply reliability in the NEM, with particular reference to the SA region. A continuing concern of the MEU has been the high costs involved in providing the services implied in the consultation paper, particularly in light of more recent events.

While the MEU is supportive of the concept of the review that has been initiated, it notes that the focus of the review is targeted on the existing structure of the NEM both in terms of the physical assets and the market concepts.

The MEU notes that the energy market concept that underpins the NEM is a cause for concern. While there was a continual growth in terms of peak demand and consumption of energy, it appears that the energy only market approach provided a basis for a market that delivered reliability of supply to consumers. What is clearly apparent from the concerns raised by a number of market participants and governments, is that with this declining demand and consumption, there is greater stress placed on the financial viability of the generators supplying a declining volume of energy; a declining volume of energy in an energy only market means that either the generators are less financially secure, or consumers have to pay more for the energy they require. As has been made clear in many submissions to the AEMC, the higher prices are placing consumers under greater financial stress, especially residential consumers in the lowest quintile of incomes and export exposed manufacturing where the higher costs of energy cannot be recovered from their markets. The upshot of these cost pressures is driving an outcome of even lower consumption.

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What is exacerbating this decline in volumes of energy supplied from conventional generators (those synchronous generators that provide inertia, system strength and control system frequency) is the increasing amounts of asynchronous generation (Solar PV, wind generation, etc) which are further displacing volumes of energy from synchronous generators, making them less financially viable resulting in either removal of needed synchronous generation (closures) and/or increasing prices for firm contracts of supply.

The outcome for consumers in the SA region clearly demonstrates these outcomes – higher prices for firm contracts which are now nearly twice the price for similar contracts in the eastern states, as the ASX electricity futures market shows:

Base Future Prices Wed 5 Oct 2016 — Full Historical Data

	NSW	VIC	QLD	SA
2017	61.22	56.67	68.55	103.76
2018	63.13	61.22	67.61	102.00
2019	64.12	65.14	67.44	98.04
2020	60.00	46.22	52.78	65.50

Further, there is the higher risk of loss of supply which has been identified by the number of rule change proposals and in the recent AEMO Roadshow on Future Power System Security.

As well as the cost for electricity, the members of the MEU are all vitally interested in system security of the electricity market. The loss of supply on 28 September in SA region exemplifies the impacts that the widespread loss of supply has on large manufacturing concerns. For example, Nyrstar has reported it is facing massive costs for cleaning its blast furnace and the loss of production for the weeks that this key element of plant is out of action[1]. There were many other users that were similarly impacted.

As consumers are already highlighting that the costs for electricity are already too high, consumers are concerned at the increased costs associated with the proposed changes to provide the increased system security that is needed.

The MEU has a concern that the AEMC SSMF review is too limited in its scope. While the MEU considers that the issues addressed within the Consultation Paper are all valid aspects that should be examined, the MEU considers that the focus of potential solutions implies that these issues can be readily addressed by setting new standards of operation in the electricity market such as identified in the five rule change requests from AGL and the SA minister for energy. The consultation paper notes that reliability is different to system security and seems to imply that approaches for providing reliability (eg transmission and distribution investment) are not elements to be considered when assessing security and this is supported in the later sections of

[1] See AFR report 29 Sep 2016 at attachment 1

the consultation paper where the focus is on addressing security through additional FCAS and other services from generators.

What concerns the MEU is that the aspects considered in the consultation paper for addressing the problems in the market could be by AEMO establishing contracts with generators to provide the additional services. What is not considered in detail is that with the increasing penetration of asynchronous generation displacing conventional synchronous generation, the competition to provide these services will be modest at best, potentially leading to very high prices for their provision and not whether other means could be identified to address the core problem.

For example, in SA region, there are times when wind generation (almost entirely asynchronous) provides for the SA region demand. The inertia needed for the market if there is a disturbance is provided almost entirely by the Heywood interconnector (Murraylink is an asynchronous provider) imposing considerable risk of the security of supply. While there is significant fast start generation (OCGT) there is limited generation that would be online at times when inertia is needed. In SA region there are only three power stations that are likely to be online when needed – TIPS, Osborne and Pelican Point with little certainty that all three would be generating at the same time.

It is clear that the issues identified in the consultation paper could all impose additional costs on consumers so the MEU considers that the AEMC needs to ensure that the solutions proposed are the lowest cost options, which requires a wider assessment of potential solutions than those implied in the consultation paper.

The MEU attaches (as attachment 2) a March 2016 report of analysis it carried out to address concerns of MEU members and other SA consumers about the high prices seen in SA for future contracts[2]. While this does not address to issues of system security to the detail that the AEMC consultation paper does, many of the issues in the MEU report have applicability to the system security framework and which addresses consumer concerns with a much wider focus than implied by the issue of just high prices. The MEU hopes that the AEMC finds this analysis useful in its approach to the system security issues.

The MEU responds to some of the questions posed in the consultation paper below

Question 1

Do you consider that the issues outlined above cover the matters that need to be considered going forward in managing changes in system frequency?

No. The MEU considers that, while the issues that need to be considered are identified, the MEU considers that the scope of the review needs to be widened to incorporate the reality that there will be increased provision of renewable (potentially intermittent) generation than that we

[2] Minor editing has been carried out (particularly in section 4) but these edits do not change the main thrust of the report

currently have. With this in mind, the MEU considers that the issues need to be expanded to include assessment of the impacts of greater renewable (intermittent) generation in the supply mix. Such an assessment will therefore include the loss of more synchronous generation (especially base load generation) and the ability of the market to accommodate these changes.

While system frequency needs to be adjusted continuously and this requires synchronous generators to be operating at all times, as even very fast start synchronous generation will have insufficient time to provide regulation and contingency raise FCAS[3].

With declining amounts of base load generation (displaced by renewable generation) the supply of raise FCAS will be more concentrated reducing the competition for its provision. Lowering frequency will require the renewable generation to have the provision to be automatically shed when the frequency gets too high. As renewable generation provides two services (supply of electricity and provision of renewable energy certificates, the MEU has a concern that lower FCAS services will become more expensive to offset the supply of both services provided.

Question 2

What do you consider to be the issues associated with low power system strength?

While the consultation paper highlights the problems with declining system strength, the implication of the loss of system strength, the MEU is concerned that the potential solutions are being focused on market solutions rather than addressing the issue more widely.

For example, could the issues be addressed in a more cost effective way by:

- moving to a capacity market rather stay with an energy only market?
- increasing interconnection?

While the MEU is not suggesting that these are the only solutions (even the most cost effective solutions) unless the frameworks review is wider than just considering introducing new ancillary services when the supply of these is likely to increase while at the same time there will be reducing competition for their supply. The MEU report attached addresses this concern, along with some other aspects.

Question 3

Do you consider it beneficial to set a standard for RoCoF? What format should this standard take and what factors should be taken into account when setting the standard? Who should set it?
Would the establishment of a new standard trigger significant additional costs to comply?
Do you consider there to be a role for maintaining system strength? Who should be responsible for undertaking this role or how should the responsibility be determined?

Question 4

[3] Although maybe some fast start generation might be able to provide 5 minute raise contingency FCAS

What roles do you consider services such as inertia and fast frequency response should play in maintaining system security in the NEM? How else could RoCoF be managed?

RoCoF is an outturn from the mix of generation that is provided in what is a competitive market and the impact of various changes in the drivers of generation. Synchronous generation already operating within a region or via AC interconnectors manages the ability to address rates of change in frequency and provides the inertia to assist in managing the disturbance. The MEU is concerned that in defining the maximum RoCoF that can be allowed in a region, this will require AEMO to procure large amounts of synchronous generation when an acceptable alternative might be to build a second interconnector to a different source of generation. Yet the decision to build a second interconnector might not include the benefits that would come from being able to better manage the inertia issue within a region.

The MEU considers that by focusing on market driven solutions, more cost effective solutions outside the market could address the problem. Further, with ever increasing amounts of asynchronous generation added to the generation mix, a solution that might work acceptably now, will be insufficient in the future. For example, converting to a capacity market for dispatchable generation might be a lower cost option than contracting with a specific generator to provide the inertia needed to keep RoCoF within its maximum allowable level.

Although accepting that the need for identifying limits beyond which security might be compromised, the MEU considers that the AEMC focus needs to be wider than merely market driven solutions.

Question 5

Do you consider it beneficial to establish new mechanisms for the procurement of additional systems security services?
What form of mechanism do you consider to be preferable and which services should the mechanism be targeted at?

The MEU considers that the aspects of system security need to be addressed more widely than just accepting the current mix of generation, the current physical assets and the current market structure. The approach needs to address the likely future generation mix (especially the amounts of synchronous generation and asynchronous generation, the levels of base load and peaking generation and the likelihood that each element is likely to be operating at any one time) and what market structure and physical assets are most likely to deliver the lowest cost for electricity to consumers in the longer term – in this regard, the MEU points out that the NEO reflects the "... long term interests of consumers".

Question 6

What form of cost recovery do you consider to be preferable in the design of a mechanism to procure additional system security services?

Should the cost recovery mechanism be designed to create stronger incentives to provide the required services?

The MEU points out that addressing the cost recovery approach is premature and should be addressed when the optimum approach is identified. For example, if increased interconnection is identified as the lowest cost option, then the cost will be paid by consumers through network charges. If the option is to move to a capacity market, then the cost would be recovered in another way. If the optimum approach is to use a market approach (as prematurely implied by the consultation paper) then the cost might be through ancillary services, a RERT approach,

The MEU would be pleased to expand on its response and if this would assist, please contact the undersigned on 03 5962 3225 or at davidheadberry@bigpond.com

Yours sincerely

David Headberry
Public Officer
Major Energy Users Inc

Attachment 1

Australian Financial Review Sep 29 2016 at 6:16 PM

BHP Billiton shuts Olympic Dam as SA bunkers down

By Ben Potter and Simon Evans

South Australia's blackout crippled the Port Pirie smelter at a likely cost of up to $7 million, Whyalla steelmaker Arrium slashed output and BHP Billiton shut its huge Olympic Dam copper and uranium mine to ride out the storm.

BHP didn't quantify likely losses but Nyrstar said the prolonged loss of power at Port Pirie had solidified the slag in its blast furnace and repairs would take up to 14 days.

Insurers began to tally the cost and Premier Jay Weatherill urged South Australians working in Adelaide on Thursday to leave their offices early and go home after police advised the winds could be worse than on Wednesday.

A BHP spokesman said critical infrastructure at the site 560 kilometres north of Adelaide was put on a back-up generator, preventing serious damage, but production had temporarily ceased on Wednesday.

"Following the loss of power in South Australia, Olympic Dam was able to safely shut down," BHP said.

Nyrstar, which processes lead and other metals at Port Pirie, fired up a back-up diesel generator but couldn't prevent the blast furnace seizing up and expects metals processing profits to suffer a hit of about €3 million-€5 million.

"We are obviously very disappointed that the power supply in South Australia has failed and the impact that this has caused to the Port Pirie plant," Bill Scotting, chief executive officer, said.

He said staff at the site are working hard to get the blast furnace up and running as soon as full power is restored, and the outage isn't expected to affect the schedule for the $500 million Port Pirie revamp.

Arrium administrator Mark Mentha said the steelworks was relying on a standby diesel generator and OZ Minerals said it shut down its Prominent Hill gold and copper mine in the north of the state without suffering any damage.

The outage took the shine off some good news for Arrium: workers accepted a pay cut that Mr Mentha says will help secure its future.

At Prominent Hill, standby generators are powering essential services and all staff are safe. Electricity networks are working to determine the full extent of damage to their transmission networks and have not given a timeline for resuming supplies.

A spokesman said the company was implementing the Premier's advice to evacuate the head office in Adelaide. "It's still pretty fluid with another front coming through at the moment," he said.

The storms will put yet more pressure on the country's biggest general insurers. QBE Insurance Australia, IAG and Suncorp have all been squeezed by rising claims from more frequent storms.

More claims

Industry insiders said initial claims had been moderate but assessors expected more claims after the second front hit.

"We don't believe the impact of this weather system on our claim volume will be as severe as first anticipated although severe wind and adverse weather conditions are forecast ... over the next few days," a QBE spokeswoman said. The main losses would likely be for business interruption and food spoilage.

Anthony Penney, head of Business SA, a lobby group, said the blackout was a major hit, particularly to supermarkets and hospitality businesses that had to discard fresh produce.

Competition has limited the ability of car, business, and home and contents insurers to lift premiums, and they have sought new reinsurance to insulate their balance sheets.

Attachment 2

EXAMINATION OF THE RECENT AND FUTURE HIGH PRICES IN THE SOUTH AUSTRALIAN REGIONAL ELECTRICITY MARKET

Assistance in preparing this report by the Major Energy Users Inc (MEU) was provided by Headberry Partners Pty Ltd. The content and conclusions reached in this proposal are entirely the work of the MEU and its consultants.

This project was part funded by Energy Consumers Australia (www.energyconsumersaustralia.com.au) as part of its grants process for consumer advocacy and research projects for the benefit of consumers of electricity and natural gas.

The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

Unless otherwise indicated, all of the NEM data and figures were produced from AEMO data using the NEMReview program provided by Global-Roam P/L

Major Energy Users Inc.

"South Australia currently gets about 40 per cent of its power from renewable energy, and … [it] is not surprising that the state's status as a national leader has also made it a target from those who want to halt progress both there and in other parts of the country.

There are many discussions taking place about planning for the future and solving technical issues, but it is disingenuous to say there is a crisis in the state. The system is extremely reliable, and the market operator says that will continue after the two coal-fired power plants are shut down next year."

Kane Thornton Clean Energy Council
Letter to editor AFR 21 December 2015

"The … South Australian power system can operate securely and reliably with a high percentage of wind and rooftop PV generation as long as the Heywood Interconnector is operational or sufficient synchronous generation is on-line in South Australia. "

AEMO, South Australian Electricity Report, August 2015, page 3

These references reflect that the SA regional market is likely to be reliable and accommodate significant levels of renewable generation. The MEU notes that there is still a residual concern about reliability in the SA region but this paper does not seek to address this aspect directly although some of the solutions considered will ease this concern.

What neither of these references reflect is the high prices being seen in the spot market, in retail contracts or in the futures market that have resulted from the impacts of the increases in renewable generation.

This paper provides a view on what is occurring and what needs to be done to overcome the significant price increases impacting consumers.

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Executive Summary

The South Australian region is seeing significant increases in the prices for the wholesale price for electricity whether measured by the futures market, the spot market or the retail market. This is having a significant and disturbing impact on SA region electricity users, whether directly through the spot market, or through retail price offerings. In comparative terms, end users in the SA region are seeing prices double those seen in adjacent regions and this is having a negative impact on SA regional industry.

To put this price hike in context, the largest 10 electricity users in SA would use in excess of 250 GWh of electricity per year. The difference in cost to a user of this size between prices available in Victoria to those available in SA is more than $10m per year. This is a cost for these 10 companies of at least the equivalent of over 1000 employees. From a residential viewpoint, it could increase electricity prices by 3-4%.

This paper identifies the causes for the higher than expected prices. The key findings are:

- The market is exhibiting increased volatility and the high proportion of intermittent generation in the SA market is increasing this volatility; increased volatility increases electricity prices to consumers
- The impact of the increasing prices for gas has been a rise in the current and futures prices of electricity. At this stage, it does not seem that the high prices for electricity reflect any significant exercise of market power, although this could eventuate with the expected reduction in competition in thermal generation.
- Renewable generation is displacing volume from thermal generation causing thermal generation an inability to recover its fixed costs leading to closures of thermal generation. These closures are in turn creating the potential for exercise of generator market power
- Forecast growth of intermittent generation is likely to create a condition where, in the absence of commercial storage options, there will be insufficient capacity to export surplus generation

The report then identifies some short term, and medium term solutions. These are:

1. Increasing generation. This would increase competition in the supply of electricity
2. Increasing interconnection. This would reduce volatility, allow greater access to Victorian prices and allow expected future renewable generation to be exported in the volumes expected
3. Combining SA and Victorian regions into one. This would allow SA consumers to access Victorian prices
4. Improving the ability to trade across an interconnector. This would allow SA consumers to access Victorian prices
5. Paying for electricity as bid. This would allow SA consumers to access Victorian prices and prices directly from wind farms

6. Paying for capacity and spinning reserve to be available and paying for volume at cost (eg RERT, specific availability payments, capacity market, etc). This would increase competition among generators
7. Limiting the exercise of generator market power. This would keep prices closer to SRMC generation prices
8. Increasing storage (eg batteries, chemical, pumped, etc). This would provide intermittent generation to provide firm hedges.

Each of these concept solutions has been assessed for viability.

The report identifies a number of actions proposed for further investigation and consideration including:

Actions for short term remedies (to seek a remedy within 6-12 months)

To ensure competitive pricing in the SA region, generators that are closing operations would need to be encouraged to remain operational. This would probably require some compensation in regard to the fixed costs they face. Options for implementing this are the RERT or a government initiated levy where consumers pay for sufficient generation to remain available to deliver sufficient competition in the SA regional market.

The MEU sees that keeping Alinta's Northern Power Station operational is a potential option but recognises that coal supply issues might prevent this occurring. If it is impracticable to reactivate Northern Station, then GdF Suez Pelican Point Unit 2 could be considered for compensation to be available.

The initial actions are to identify if the payments required to be available provide a better outcome than business as usual.

Actions for medium term remedies (to seek a remedy within 1-3 years)

The apparent best outcome would come from increased interconnection of some 2000 MW capacity with Victoria. This will remove the need for providing payments to keep generators available.

To implement this action will require discussions with ElectraNet/AEMO to identify the best options for interconnection and to compare the costs with other options and business as usual

The MEU has noted that these short and medium term concepts for solutions are reflect what is currently seen in Germany which also has been aggressive in the expansion of renewable generation. The solutions developed in Germany are similar to that proposed by the MEU - a mix of capacity payments for generation coupled to increased interconnection[4].

Longer term actions (a remedy in >3 years): there needs to be a solution that addresses the issues seen in SA region on a NEM wide basis. Such solutions might include a change from an energy only market to a capacity market, lower cost storage solutions, increased interconnection and/or pay as bid options.

The MEU does not see that its proposed short and medium term actions and solution concepts to address the immediate SA region problems would detract from any of the longer term solutions that might need to be implemented on a NEM wide basis.

The first step for implementing the further assessment process is to test the viability of the options considered. Once this identifies the best solutions to address the problems, an action plan must be developed to deliver each of the solutions identified. This action program will need to include targets for consideration for each of the proposed individual action plans.

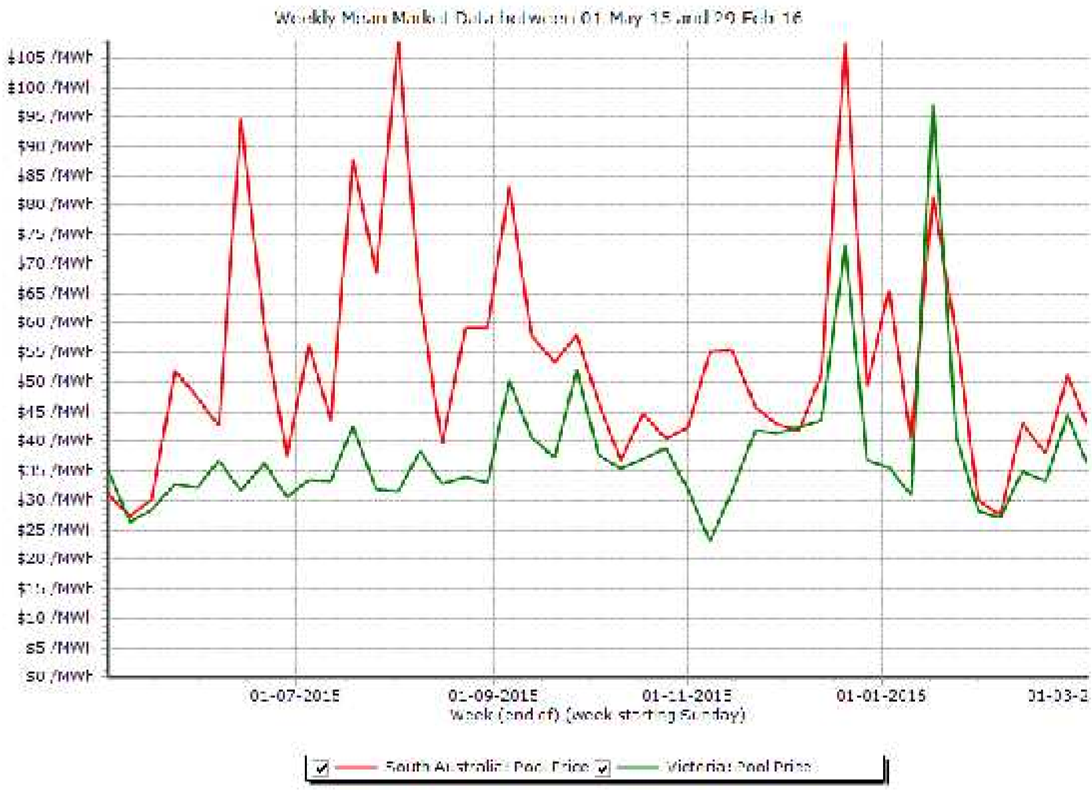
[4] See http://www.europeangashub.com/custom/domain_1/extra_files/attach_597.pdf

1. Introduction

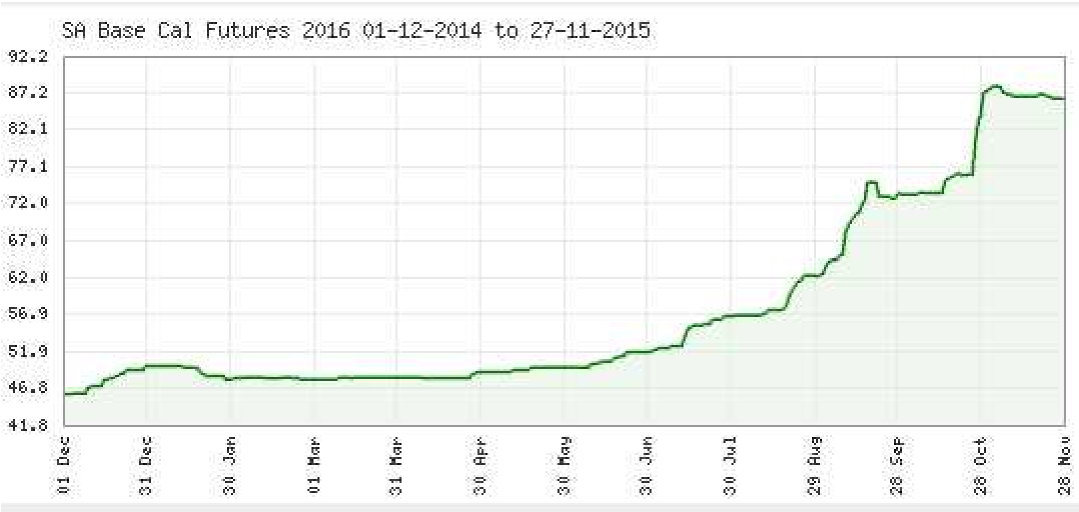
Since the middle of 2015, the electricity wholesale market in South Australia has exhibited a substantial increase in volatility coupled to resultant high prices approaching similar levels last seen in 2008 - 2010 period when it was considered by some consumers that AGL used the market power held by its generators to drive wholesale prices higher. AER State of the Energy Markets reports during this time also made reference to its concerns about the exercise of market power.

SA average prices for the latter part of Q2/15, all of Q3/15 and Q4/15 were twice what were seen in adjacent jurisdictions (eg as in Victoria), yet demand in the SA region remained low and there is more than sufficient installed generation to meet the regional demand. While there is still significant separation of prices between SA and Victoria into early 2016, the futures markets have indicated this separation has reduced somewhat from the levels seen in 2015.

SA daily median and mean prices Jun15 to Feb16



Also, since the middle of 2015, the SA base load futures market has been signalling a very large increase in future SA electricity prices. The increase in the base load futures for 2016 provided by ASXEnergy.com.au highlights that prices started increasing about the same time that the SA regional spot prices started trending upwards, from May 2015. This trend in futures prices is shown on the following two figures and one table accessed from ASXEnergy.com.au on 27 November 2015.



Source: ASXenergy website

In contrast, the movement of Victoria's base load futures exhibited significantly lower price movements

Source: ASXenergy website

Further, the base load futures market prices for SA (27 November 2015) for calendar years 2016, 2017 and 2018 are more than twice those forecast for the Victorian region which is directly connected to the SA region. Liquidity in the futures market has also been seen to reduce significantly.

Base Future Prices Fri 27 Nov 2015				Full Historical Data
	NSW	VIC	QLD	SA
2016	43.06	37.64	57.04	86.39
2017	45.80	38.89	55.99	88.46
2018	47.94	40.85	60.01	86.33
2019	47.40	41.90	53.33	58.71

Source: ASXenergy website

What is interesting about these futures prices is that, after the start of 2016, the futures prices for 2016 (being based on the last three quarters of the year) show a significant fall compared to those published in November but the prices for 2017 and 2018 maintain their high levels with the prediction that levels will fall to those experienced in the 2016 period, in 2019.

Base Future Prices Mon 7 Mar 2016				Full Historical Data
	NSW	VIC	QLD	SA
2016	44.10	39.92	57.24	65.10
2017	46.11	40.45	56.13	77.71
2018	46.80	40.02	56.73	89.69
2019	49.24	41.90	53.37	63.64

Source: ASXenergy website

More recent futures prices reinforce that base prices for the SA region are still holding into 2018 and 2019.

Base Future Prices Tue 12 Apr 2016				Full Historical Data
	NSW	VIC	QLD	SA
2017	47.48	42.26	58.19	77.61
2018	47.42	41.05	57.75	88.08
2019	49.24	41.90	54.18	70.00

Source: ASXenergy website

Major Energy Users (MEU) members are advising that these futures prices are being reflected in actual offers by retailers for firm contracts prior to each year commencing. Further, they also report that they are receiving only one or at most two retail offers for their future supplies, reflecting a significant loss of competition at the retail level, similar to that seen in the 2008-2010 period when there were difficulties in obtaining any (let alone competitive) hedges from generators. Similar comments were made at the Roundtable conference called by the SA government on 15 December 2015 to discuss high SA electricity prices and at another SA government sponsored conference on 24 February 2016. Other than highlight the problem, no solutions to address the high prices were proposed at either of the roundtable discussions.

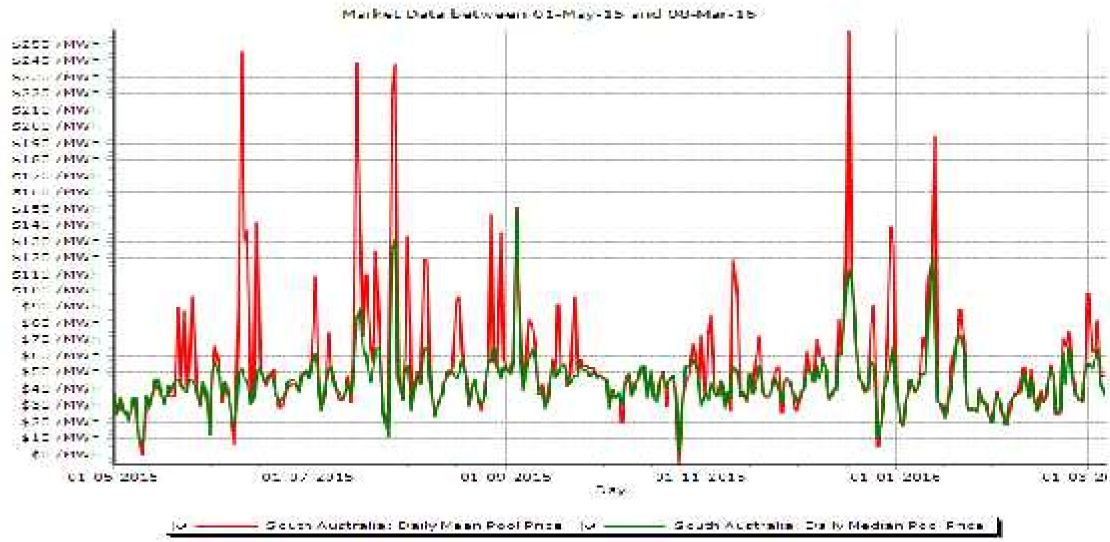
Unnecessarily high wholesale prices are a cost to consumers, either directly to those exposed to the spot market or, over time, to all consumers (including residential and small business consumers) as they renew their retail contracts. As electricity is such an important element of the economy, these high prices are having a dampening effect on the SA economy overall, with the potential for loss of jobs and increased stress on households.

High prices in SA started to become a significant issue in recent months (eg see AFR article 21 September 2015 - "Ripped off: Energy users in SA, Qld see red"). The SA government has indicated great concern (eg see AFR article 14 December 2015 - "SA government in energy market crisis talks with industry, suppliers") which preceded the 15 December Roundtable conference called by the SA government.

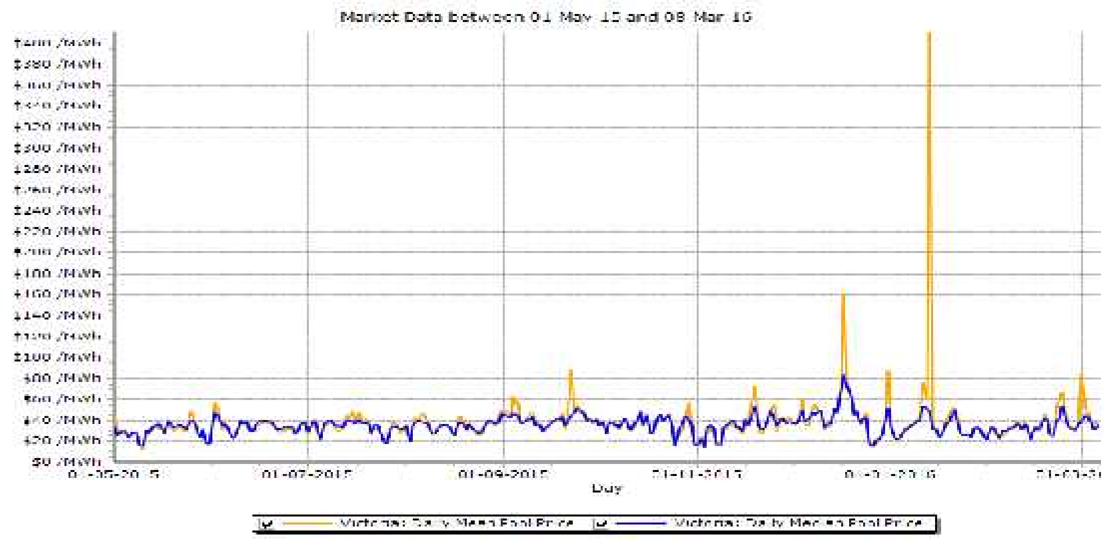
These concerns of high prices are exacerbated by excessive volatility in the electricity market which increases the costs to manage the risks faced by retailers in providing fully hedged prices to consumers, with these costs being passed onto consumers by retailers.

The extent of this volatility in the SA region is reflected in the significant disconnect seen between the median prices (those most commonly seen) and the mean prices (the time weighted average of all prices). The following two charts show the difference between median and mean prices in SA in recent months and those in Victoria which have a much closer correlation.

Mean and median prices in SA



Mean and median prices in Victoria



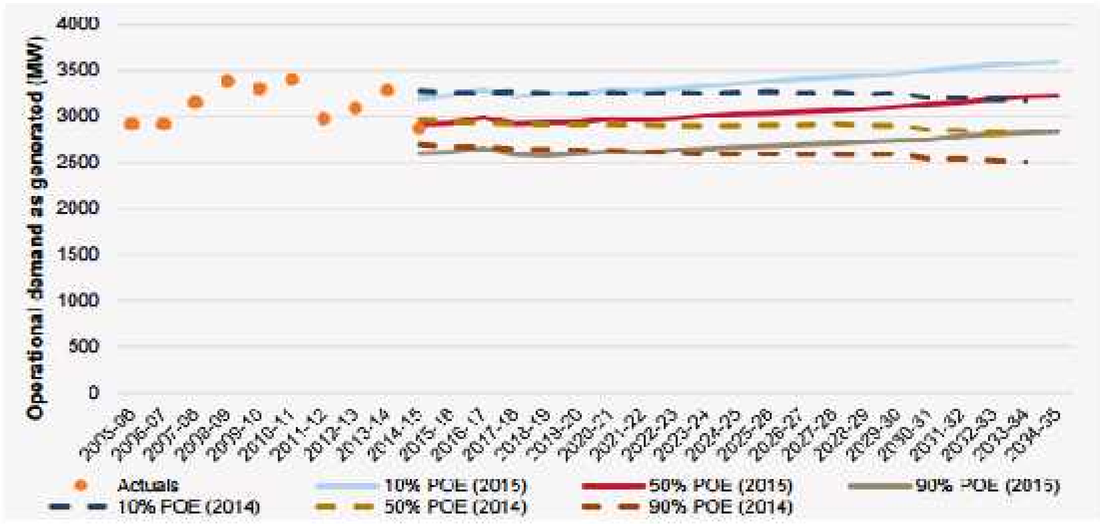
The disconnect between median prices and mean prices supports the view that there is much greater volatility in the SA market than seen in other regions. This greater volatility has a significant impact on retail prices as higher volatility imposes a greater risk on retailers and therefore retailers seek a risk premium because of this.

The purpose of this paper is to analyse what is causing these significant changes in the SA regional market and to identify potential options for addressing the causes.

2. The SA regional electricity supply in context

SA regional peak demand has fallen in terms of consumption and to a lesser extent in demand, with demand in the region not forecast in the next 10 years to exceed the highest historical demand recorded to date. This is shown in the AEMO National Electricity Forecast (NEFR) for 2015.

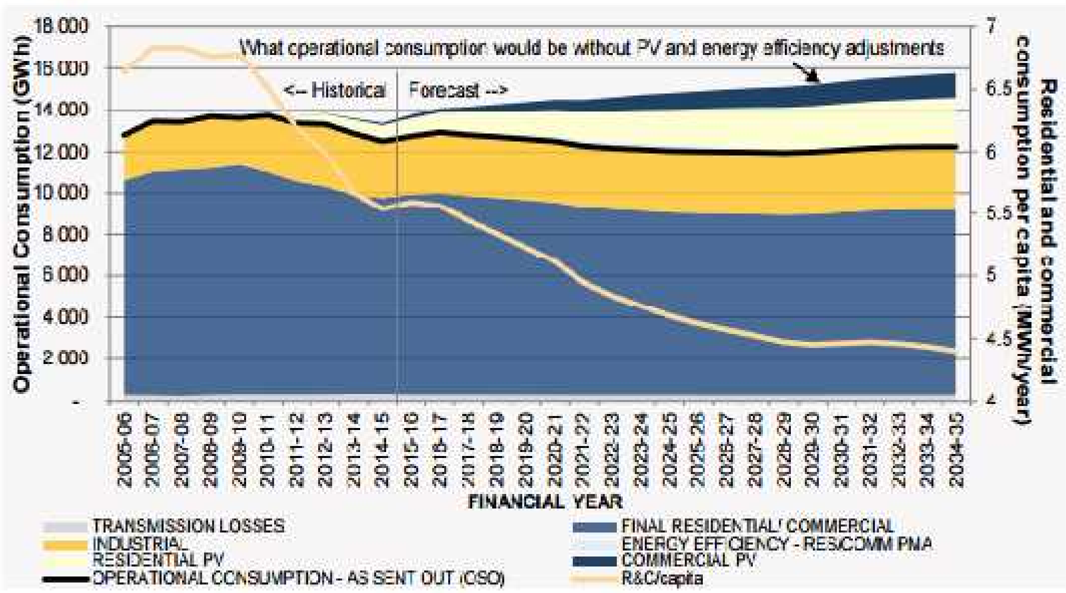
Figure 33 Summer 90%, 50% and 10% POE maximum demand forecasts for South Australia



Source: AEMO 2015 NEFR

The same NEFR shows that the consumption of power from power stations is also falling and this is shown in the following chart:

Figure 26 Summary of operational consumption by key component in South Australia



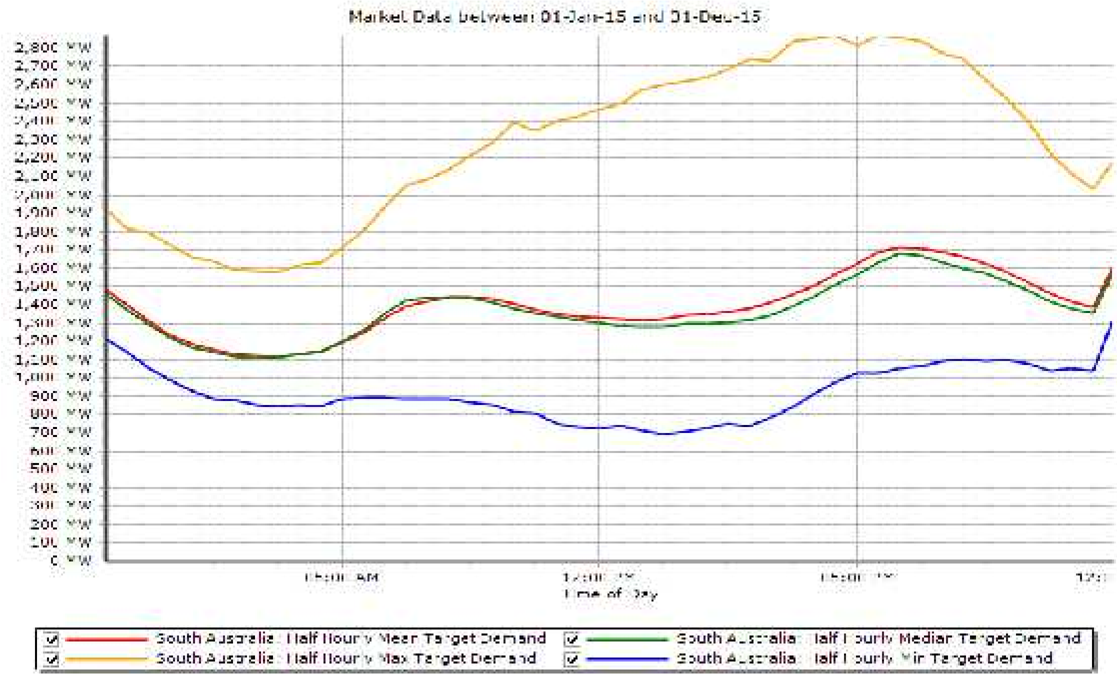
Source: AEMO 2015 NEFR

SA regional consumption has consistently fallen since 2011 to the present time and is forecast over the next 10 years to fall further. Overall, there is an expectation expressed in the NEFR that consumption in the region will fall by some 15% from 2011 levels over the next 20 years.

At the same time, the 2015 NEFR identifies that peak demand in the region has also fallen and forecasts peak demand will not exceed previous system high demands for over a decade, even under its high forecast regime.

The daily load shape for SA demand over the past 12 months is shown the following chart This highlights that there is still considerable risk of major, but relatively short term, demand increases compared to the average (mean and median) load shape currently seen in SA.

Average daily SA demand 2015



Recognising the chart reflects average daily load shapes, the fact that the mean and median traces are similar supports a view that although the peak demand reflects a much greater move away from the average than the minimum demand; this demonstrates that the SA market is significantly impacted by short term high peaks, with these "needle" peaks relatively infrequent.

Overall, the SA electricity market is seeing:

- Declining consumption and therefore falling average demand
- A relatively static peak demand is forecast after falling peak demand in recent years
- A significant change in average daily load shape with a "sag" in the middle of the day.

The changes in demand and consumption in the SA market are to some extent a result of the impact of the Global Financial Crisis (GFC) on the manufacturing sector but probably more so by the impact of renewable generation in SA. This aspect is discussed more fully in the following sections.

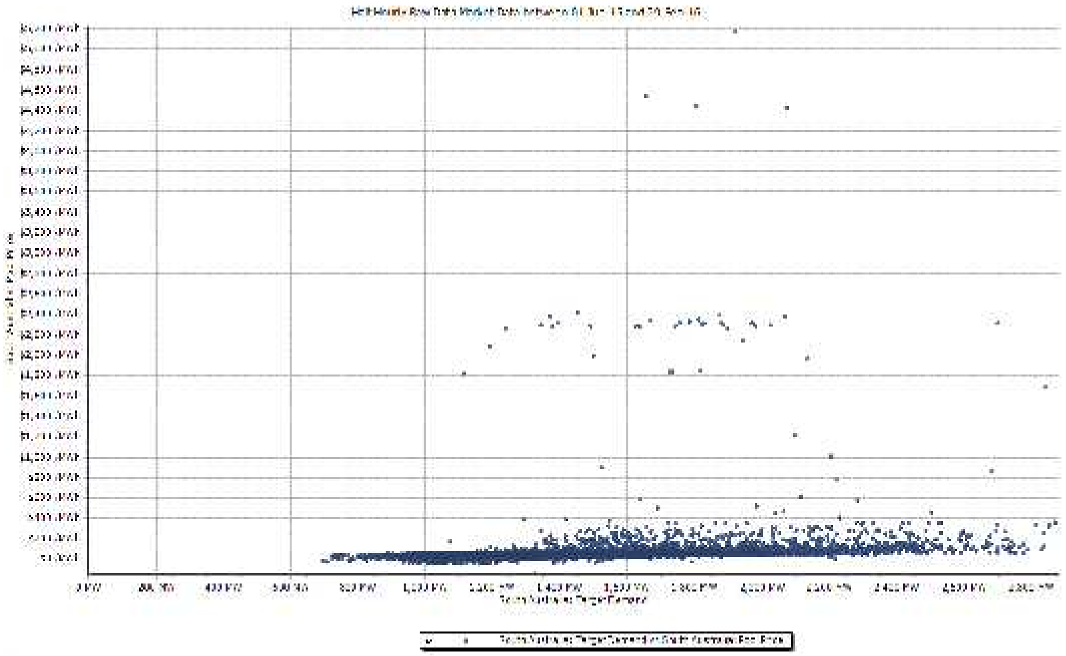
2.1 When are the high spot prices occurring in SA region?

Analysis of the 9 months of data from June to November 2015 shows that there were 38 price spikes above $1800/MWh for this period. Further analysis shows that these prices are associated with just one or two dispatch price excursions to near Market Price Cap (MPC) in the trading period.

All of the price spikes did not occur at the peak demands seen in the period and only five occurred when the demand exceeded 2000 MW in the region[5].

The following chart shows the high price events relative to demand.

SA Price v demand Jun/15-Feb/16

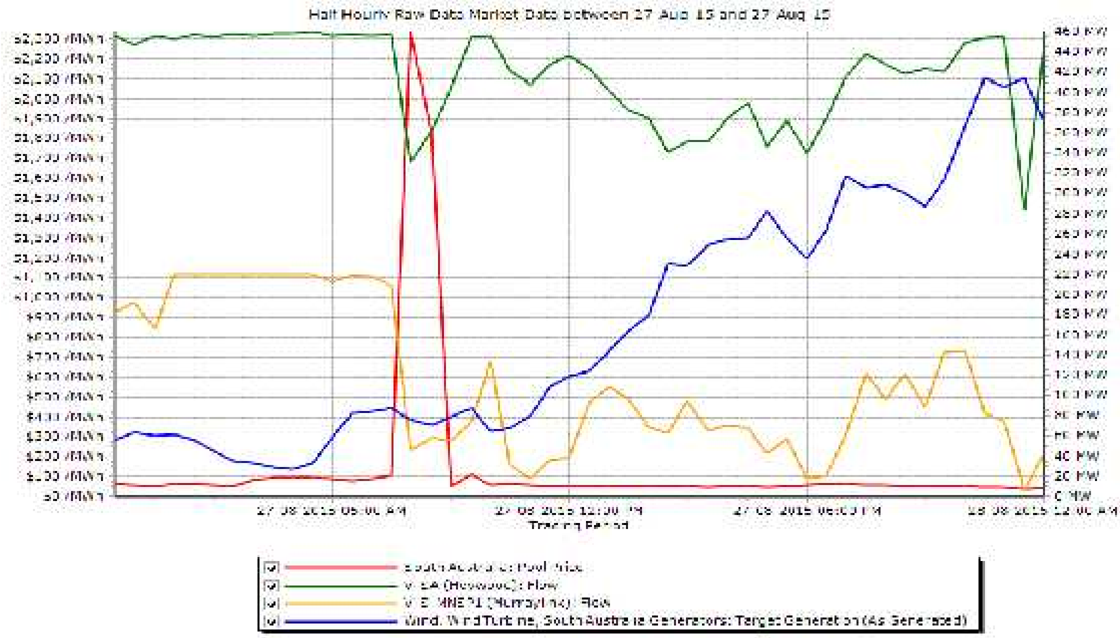


The time weighted average demand through the period was $55.6/MWh but exclusion of the 38 price excursions reduces the average time weighted price to $48.7/MWh, a nearly 15% reduction.

Deeper analysis of the pricing shows a clear pattern - these high price incidents tend to occur when wind generation is low or falling and there is a disturbance on the interconnectors, (such as congestion limiting supply from interstate) coupled with an increase in regional demand. An example of this is shown graphically in the following chart:

[5] The peak demand seen in the region was 2870 MW during the period under investigation

SA spot trading interval data 27 August 2015



Analysis of the five-minute dispatch data reinforces the view that the regional price spikes for just one dispatch period, before settling on a much lower price.

The conclusion from this is that low generation from wind is impacting the dispatch structure when the interconnectors lose capacity or are not able to make up the difference in the short term with high priced generation being required to be dispatched (usually for only one dispatch period in a trading period with bids near MPC) during which time other lower price generation ramps up. That this same effect does not seem to occur when wind generation is high, implies that wind and interconnector supply coupled with the base load generation dispatched has sufficient ramp rate to accommodate load increases.

The MEU points out that these conditions could also provide the opportunity for a base load generator to "economically withdraw capacity"[6] and move that capacity to a higher price band. This report does not investigate whether the high price is caused by calling fast start generation or gaming.

It is probable that the disturbances seen on the interconnector from mid-2015 to current times were more likely to be associated with the construction works for the Heywood interconnector upgrade, but this still indicates that any disturbance (including on the interconnector) can lead to a condition where a short term price spike can cause considerable price pressures from the market, with little opportunity for demand side responses to mitigate the cost impact.

In particular, the MEU notes that the price spikes currently experienced by SA consumers have had a significant impact on price volatility and volatility from this source will be a continuing problem even after the upgrading work on the interconnector is completed. Retailers will have to build into their retail prices a premium to manage this increased volatility.

[6] Economic withdrawal of capacity is a well recognised tool for generators with market power to increase their revenues

But if the spikes settle down after the upgrade works are completed in mid 2016, what is driving the high futures prices for the next three years and why is there reduced liquidity?

2.2 The impact of the RET in SA

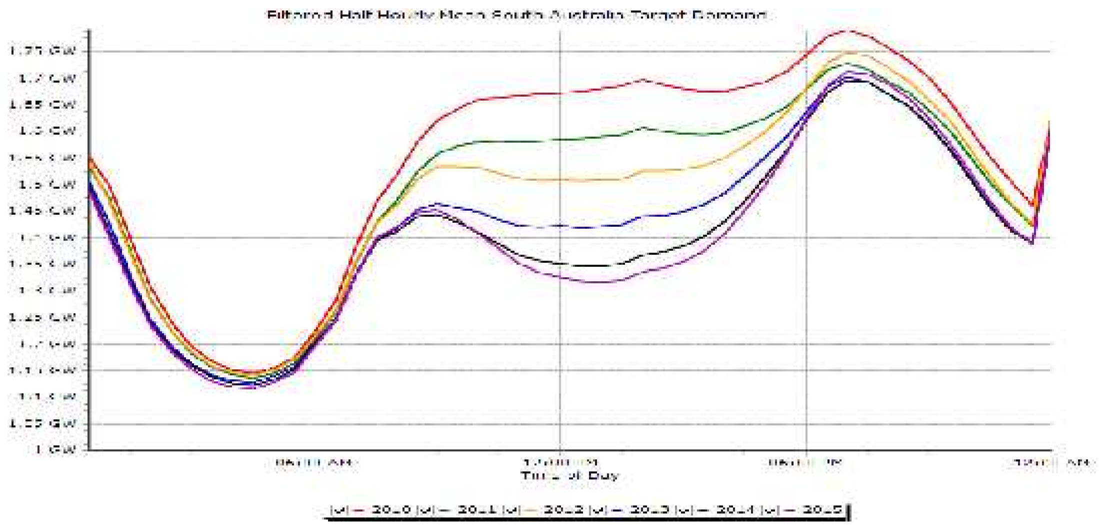
This review is not intended to debate the Renewable Energy Target (RET) decision to incentivise the growth of renewable generation in Australia but it does highlight the impact of the RET has had on the SA electricity market.

There are two renewable energy programs that are impacting the SA regional market - large wind farms and the high penetration of roof top solar PV. The first displaces existing generation from being dispatched and the second reduces the overall regional demand.

Since the decision in 2008 was made to expand the RET scheme to 20% of generation by 2020, the SA region in particular has seen a major increase in wind generation, primarily due to its admirable location to harness wind energy, and in roof top solar PV generation, further incentivised by large feed-in tariffs.

The impact of roof top solar PV has had a significant impact on the demand pattern for electricity in SA as seen in the following chart which tracks the average daily load shape over the last five years

SA annual average daily load shape 2010 to 2015.



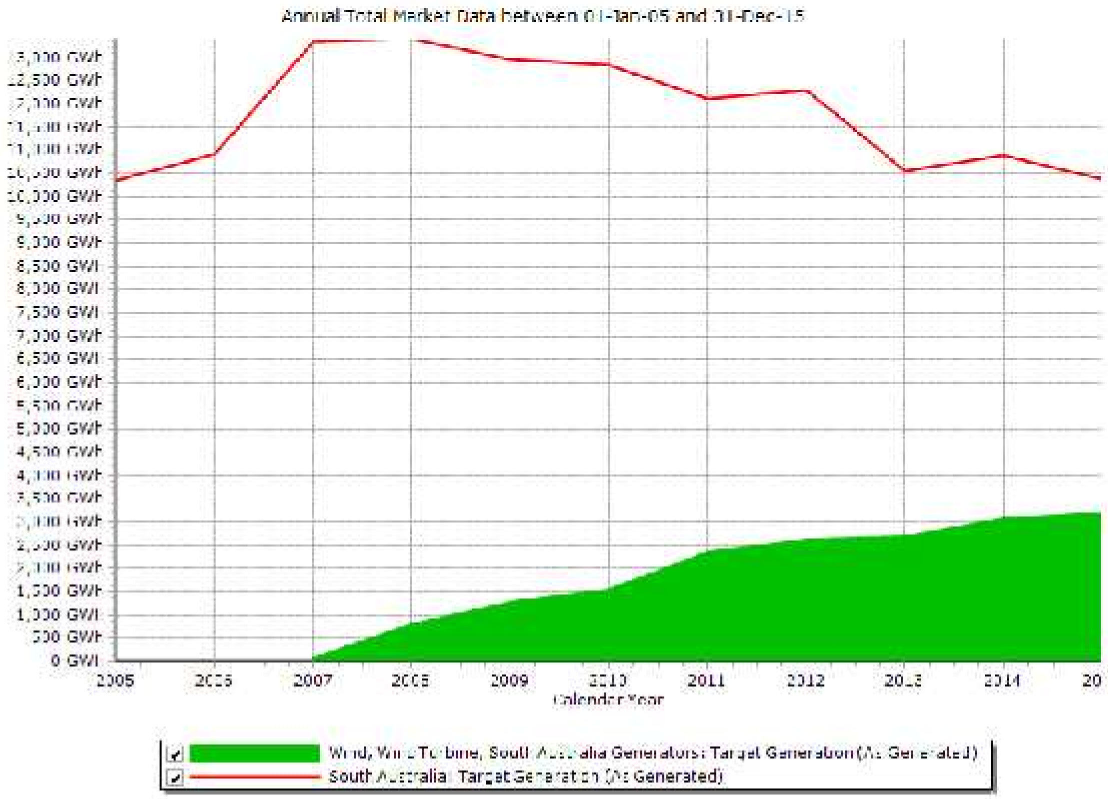
The chart above shows the increasing impact of roof top solar PV generation changing the pattern for supply into the SA market. It highlights that the rooftop solar PV impacts especially in the middle of the day. Before the growth in rooftop solar PV, demand in the middle of the day was essentially flat before increasing to a peak early evening. As the growth in PV has occurred, there is a distinct "hollowing out" or "sag" in demand from the late morning to mid afternoon[7].

[7] AEMO makes this observation in its report on 2015 NEFR (minimum demand data - SA)

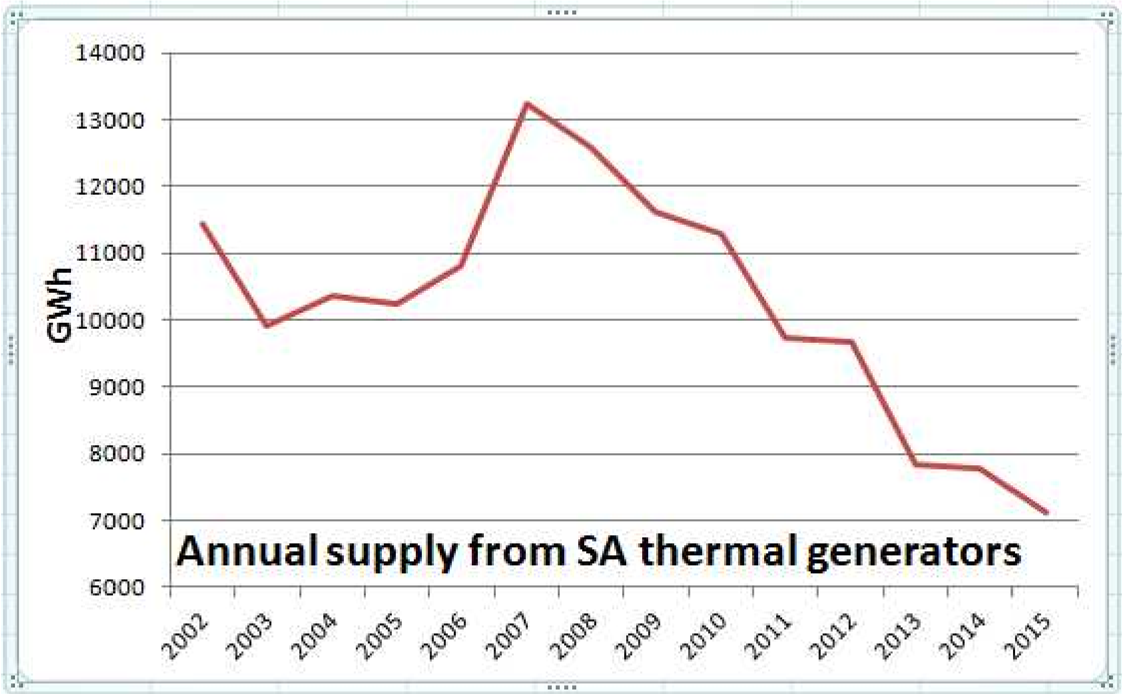
The above chart also highlights another phenomenon as the falling peak demand in the early evening is not replicated to the same extent in the early morning. The chart is indicates that the drive for increasing energy efficiency is impacting residential users at the peak demand time of day (early evening) although energy efficiency impacts are being seen more generally too.

The impact of wind generation is seen in the following chart which shows the growth of wind generation in SA since the start of the RET. The growth in wind generation has moved from having almost no impact on the SA electricity market until about 2007 to a point where now it provides a significant share of the total volume of electricity supplied from the market, reaching 31% of the total volume of generation in 2015. This proportion of total volume of the SA demand will increase as planned wind farms are added to the fleet.

SA annual total of generation and wind generation



However, this is not the whole story. In addition to the increasing amounts of wind displacing regional generation, there is considerable imported generation via Murraylink and Heywood interconnectors. These flows further displace volume from regional thermal generation. The following chart highlights that the amount of regional thermal generation required in the region has fallen from a peak in 2008 to nearly half that amount in 2015 and there is an expectation this will fall further.



Source: AEMO data, MEU analysis

Currently about 7000 GWh pa is needed from thermal generators in SA but with the forecast increases in rooftop solar PV and wind farms this will further fall as more volume is displaced.

Further, with the expected increase in capacity of the Heywood interconnector by some 45% by mid 2016, this will further reduce the amount of electricity needed to be supplied from regional thermal generators.

The impacts of these ever falling consumption needs are examined in the next sections.

2.3 The RET and SA regional generation

The NEM is based on an energy only trade in electricity which reimburses generators on the volume of electricity they supply[8].

Base load generators have a large capital cost that has to be recovered by selling power in large volumes. This means that, although the short run marginal costs (SRMC ie fuel and labour costs) are low for base load generators, their selling prices have to be much higher than SRMC to recover their fixed costs.

[8] Distinct from the energy only markets as used in the NEM, other competitive electricity markets are based on a mix of capacity and energy where a generator is paid for guaranteeing to provide an amount of capacity as well as energy.

In a competitive energy market, generators should be dispatched based on their short run marginal costs and so base load generators with large capital costs have to sell large volumes in order to cover their capital costs[9]. Reducing the volume of sales makes the base load generator less commercially viable; reducing the volumes of sales would normally be offset by an increase in price.

As wind farms have very low short run marginal costs and therefore they are dispatched ahead of even low short run cost generators such as base load generators. The increasing volume of electricity supplied by wind farms therefore displaces the volume of electricity provided by regional thermal generators. Coupled to this, there is a net flow into SA from Victoria via the interconnectors which also displaces SA regional thermal generation as Victorian brown coal fired generation generally has a lower short run cost than the gas fired SA regional generators.

The lower volumes of electricity sourced from the SA thermal generators (a result of the lower consumption in SA particularly driven by the large amount of roof top solar coupled to the higher incidence of wind farms) has led to the closure or part closure of base load generation throughout the region, presumably due to insufficient sales to underpin the capital and operational costs involved.

Specifically, Alinta has already closed its Playford power station and proposes to close its Flinders power station at the end of Q1 2016[10]. GdF Suez has announced that it will formally close half of its generation capacity at Pelican Point (unit 2) in the first half of 2016[11] and AGL has advised closure of Torrens Island A power station[12] in mid 2017.

The overall impact of these closures is to remove over 1250 MW of base load capacity from the SA regional generation, leaving about 1200 MW of base load power, of which AGL will control some 800 MW. The remaining thermal generation in the region mainly comprises high priced, low efficiency gas fired open cycle gas turbine generators of which there is some 900 MW installed in the region.

There are two critical aspects of this reduction in base load generation in SA.

1. Despite the high levels of wind and solar generation available, neither of these forms of generation can provide firm offers for electricity supply due to their essential intermittency. While there is firm supply via the Heywood and Murraylink interconnectors, the arrangements for adjusting for inter-regional price differentials do not provide an ability for firm contracting of supply. This means that the only source of firm contracting of supply comes from the regional generators, with the base load generators being the prime source of these firm contracts. Further, these are also the generators that are needed and able to provide regulation and short term contingency frequency control ancillary services (FCAS).

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[9] This fixed cost is amortised over large volumes of sales but if the volume of sales falls, there is insufficient recovery of the fixed costs to keep the operation viable.

[10] See Alinta news release 7 October 2015 available at https://alintaenergy.com.au/about-us/news/flinders-operations-update

[11] See appendix 1 or http://www.adelaidenow.com.au/news/south-australia/pelican-point-power-station-will-cut-more-than-half-its-generation-capacity-early-next-year-threatening-jobs/story-fni6uo1m-1226978458743

[12] See https://www.agl.com.au/about-agl/media-centre/article-list/2014/december/agl-to-mothball-south-australian-generating-units

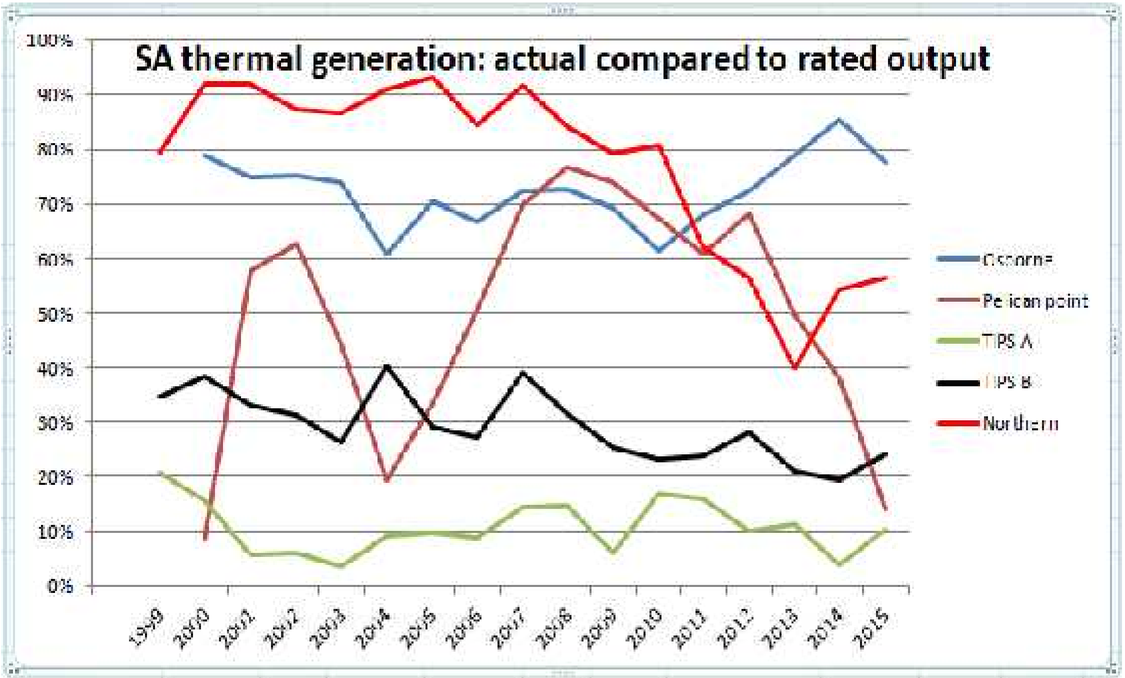
2. The closure and planned closure of the base load generation has resulted in a significant reduction in competition for firm contracts in the next few years.

2.4 What thermal generation capacity is needed in SA?

In financial year ending in 2015, Heywood interconnector provided a net 1877 GWh of electricity to SA from Victoria[13]. At its current 460 MW rating this is a net load factor towards SA of over 45%.

Pro-rating the increased capacity of Heywood at the same load factor would displace about another 800 GWh (perhaps even more with less base load generation in SA) leaving regional thermal generation to provide only 6000-6400 GWh pa. This amount of electricity would provide a capacity factor of about 60% for the three remaining base load power stations (Osborne, Torrens Island B and unit 1 at Pelican Point) after the others are formally closed.

The following chart shows the actual output of the five main thermal generators compared to their rated (peak capacity) output (ie their actual capacity factors), which shows the impact of the declining volume of electricity from the thermal base load generators. The chart shows clearly why Pelican Point unit 2, Northern and TIPS A stations are forecast to be closed.



Source: AEMO data, MEU analysis

[13] The impact of Murraylink is modest. In 2015 Murraylink had a small net flow to Victoria. It is not expected that this would change significantly as Murraylink commonly flows counter price into Victoria due to constraints in the Victorian transmission network but when Heywood flows into SA, constraints in both the SA and Victorian transmission networks frequently limit flows to SA on Murraylink, especially at times of high demand in SA.

In 2008, the base load thermal power stations provided over 85% of the regional consumption of electricity. Using this capacity factor implies that SA region might need some 950 MW of available base load thermal generation for the volume of 6000-6400 GWh expected in SA from mid 2016.

As the combined output of Osborne, Pelican Point unit 1 and TIPS B provides over 1200 MW, then the base load generation provided by these should be capable of providing the necessary regional generation supplies at most times with the existing 900 MW of installed open gas turbines providing for the balance of peak demand.

While the assumptions work out for the average conditions, the forecast 10%PoE[14] demand for SA region up to 2030 is expected to be no greater than that experienced in 2008 and 2010 (ie about 3500 MW). With base load generation capacity of 1200 MW, Heywood capacity of 650 MW and 900 MW of OCGT generation, there will be some 2750 MW of firm thermal supply based on existing generation after the forecast closures. While in theory Murraylink can provide another 200 MW, transmission network constraints usually limit its ability to provide its full capacity at times of peak demand.

In 2014, the peak demand in SA was 3240 MW and in 2016 to date, peak demand reached 2718 MW. This indicates that the available generation and inflows from Victoria would only just meet the 2016 peak demand and not meet the 2014 peak demand.

AEMO advises there is another 570 MW of OCGT generation forecast to be added to the regional fleet (2015 ESoO), increasing the thermal generation capacity. While some new wind generation might be added to the generation fleet, there is no certainty that the peak demand will be met by the available and forecast capacity.

Further, the AEMO forecasts assume that there will be some capacity that is not available when needed.

It would be with this in mind, that AEMO has forecast that unless there is change in the supply dynamics in the SA region, under its medium and high demand scenarios, SA region will breach the Reliability Standard in 2019/20, and that there is still the likelihood of forced outages in 2016/17 and an even greater likelihood in 2017/18 but perhaps not enough to breach the Reliability Standard.

What this assessment also highlights is that even under normal operating conditions, TIPS B power station will be pivotal in the regional supply arrangements and will have significant market power.

2.5 The apparent dichotomy

When the spot market prices rise, there is a view that the cause of this is due to a shortage of supply. This price rise is intended to provide a signal for new investment.

[14] Probability of Exceedance

The MEU notes that subsequent to the MEU rule change on generator market power proposed in late 2010[15], the AEMC provided its view on how the AEMC measures whether prices in a region are excessive - that is by use of a long run marginal cost (LRMC) methodology. This approach essentially assesses the regional price against the LRMC that a new entrant generator would require to be financially viable. The AEMC asserted that high prices are a signal for new generation investment and that it is only when high prices in excess of the LRMC of a new entrant occur and are sustained, that action might be needed to address the high prices as they might signal that the high prices reflect the abuse of market power.

But what is occurring in SA region in concert with the high prices, are generation plant closures, especially of base load generation[16].

In contrast to when the AEMC developed its LRMC measure to assess if prices were excessive, the SA region is now being presented with closures of base load generation and high prices. However, as there are more proposed closures of generating plant even with high prices forecast, assessments of the market prices based on a cost to introduce new plant cannot now be seen to apply[17].

Actual closures of generating plant, with proposals for more closures, are usually because of an oversupply in generation, with the oversupply causing low prices due to competition as has been seen in other regions. In SA region, there are closures occurring (and more forecast) because of over-supply, despite there being high prices; this outcome is counter intuitive when assessments are made based on price signals.

The recent announcements about closure (full and partial) of some SA thermal power stations adds to the view that the high prices are a result of very high penetration of wind generation coupled to high penetration of roof top solar generation when outputs of these renewable generation sources are related to regional demand. But high prices coupled to high penetration of renewables generation is also counter intuitive as there is an expectation that large amounts of renewable generation with their low SRMC would lead to lower prices[18].

Overall, the RET is achieving its goal of reducing carbon emissions by displacing volume of generation from the thermal generators, but there are repercussions as this occurs.

The augmentation of the Heywood interconnector (currently in hand and due for completion mid 2016) will allow greater transfer of power into SA from Victoria and this should have some impact on SA prices although this is not seen in the futures market pricing. This could be a result of the upgrade being insufficient in size to impact prices.

The augmentation for the Heywood interconnector is leading to further reductions in the volume of electricity required to be sourced from SA thermal generators.

[15] See http://www.aemc.gov.au/Rule-Changes/Potential-Generator-Market-Power-in-the-NEM
[16] See for example appendix 2
[17] Especially when the lowest SRMC thermal plant in SA region (Northern PS) is being shut down.
[18] See, for example, ACIL Allen report for the 2014 Warburton Expert Panel review of the Renewable Energy Target which considers that increasing renewable generation will reduce wholesale market prices.

2.6 The impact of gas price rises

In addition to the other issues facing the SA region, the price of gas in the region is already increasing and is forecast to reach between $7-8/GJ plus the cost of transport to the various power stations. This higher price reflects a price increase of ~2 times for gas in "real" terms and, as SA thermal generation is predominantly gas fired, any increases in the cost of gas will place further pressures on the SA regional electricity market.

The impact of these higher gas prices on the SA thermal generators will be significant, even to the extent that the forecasts for power prices in the ASX electricity futures might well reflect the actual costs of generation from the SA thermal generators expected to be in service in 2016-2018; a recognition that the volumes of generation will also be lower due to even more wind generation and increased flows on the interconnector exacerbates the problem and puts further upward pressure on prices.

While volume and time weighted spot prices for electricity in the region could well be below the futures prices, it is the structure of the SA regional market that sets the futures prices being offered for forward hedges.

The heat rates for TIPS B, Osborne and Pelican Point (the three base load generators forecast to be remaining in operation in the region) are 11.40GJ/MWh, 8.14GJ/MWh and 7.35 GJ/MWh respectively[19] which implies that at $7/GJ for gas the cost of generation at TIPS B would be approaching $80/MWh. Adding fixed and variable operating costs, the short run marginal cost (SRMC) for TIPS B is approaching the futures pricing for 2016-2018[20]. While the SRMCs for Pelican Point and Osborne are much lower (perhaps $55-65/MWh using $7/GJ gas[21]), the combined volume of electricity offered by these two base load stations provides only about half of the volume of electricity that TIPS B can offer.

That the futures prices and the forecast SRMC for electricity from the largest thermal generator in the region when operating with a delivered gas price of $7/GJ are similar is consistent with the view that only regional base load thermal generators are providing firm hedges for electricity supplies in the region.

2.7 The impacts on retail activities

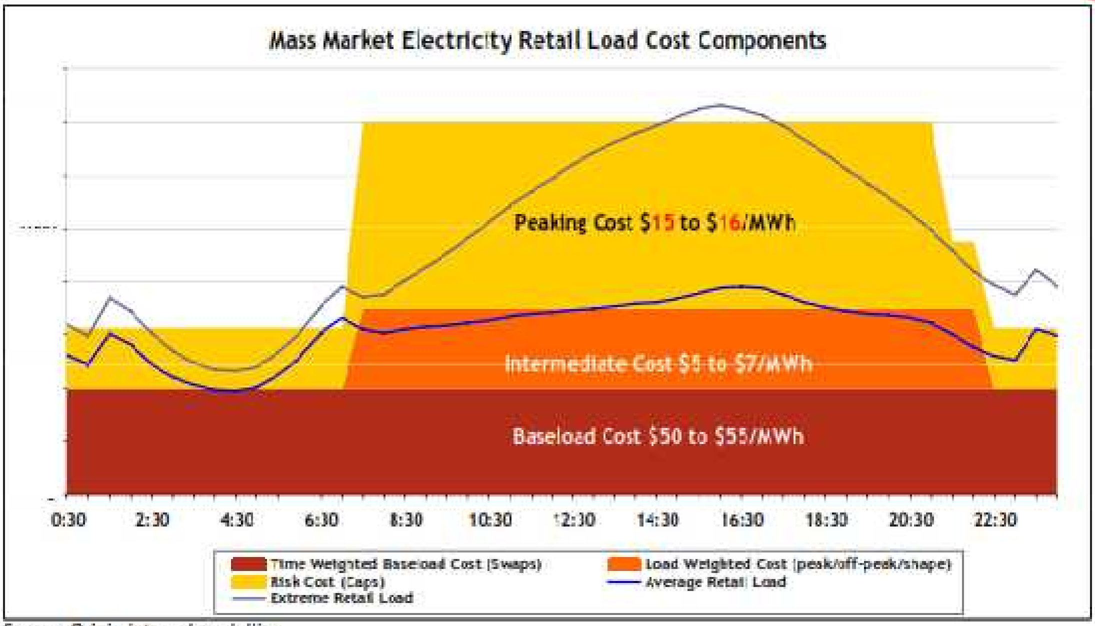
A retailer bases its hedge book in the following manner.

All retailers have to access their electricity needs from the NEM. While retailers can be generators too (commonly referred to as "gentailers") some retailers access some or all of their

[19] See for example Table 14 in report by ACIL Tasman for the Inter-Regional Planning Committee "Fuel Resource, New Entry and Generation Costs in the NEM", April 2009
[20] The heat rates for TIPS A and the open cycle GT peaking generators are even higher than for TIPS B at 12.39GJ/MWh (TIPS A) and ~13GJ/MWh for the open cycle generators.
[21] ibid

needs from third party generators, many of which may be competitors in the retail function. This then creates tension between gentailers and retailers and provides gentailers with an advantage in the electricity market and tends to drive "pure" retailers to source their generation hedges from those who are mainly generators and not significant competitors in the retail space.

A retailer builds up a "book" of various forms of generation contracts. The following chart[22] shows how such a book build for a retailer is created:



Source: Origin internal modelling

What this chart shows is that the bulk of the electricity sourced by a retailer (perhaps exceeding 90%) is via hedge contracts with one or more generators. What it also highlights is that while much of the generation sourced is offset against a counterparty, there are parts of the retailer requirements that are not offset by contracts with others - this means that the retailer has to source its needs directly from the wholesale spot market, either to sell for an overweight position or to buy for an underweight position. This need to trade in the wholesale market increases a retailer's risk significantly and is driven by the retailer's need to accept the volume and timing risks imposed by its customers who use electricity as and when they need it without understanding the risks that are carried by the retailer and how much the retailer adds to the purchase prices of the hedges that it establishes in order to accept this risk.

It is noted that there is apparently significant competition in the retail function of the SA electricity supply chain. There are currently over 60 retailers authorized by the AER to operate in South Australia although a number of these are duplicates (eg AGL has four separate authorizations). It is also noted that interstate generators are authorized retailers along with the recognised dominant retailers in the NEM of AGL, Origin Energy and EnergyAustralia, and a number of smaller independent retailers and gentailers.

It has been observed that a vibrant retail function requires an ability for retailers to be able to access generation hedges from a number of generators. The fewer generators providing hedges

[22] This chart was presented by Origin Energy at an AEMC Reliability Panel discussion in 2010. Note the prices quoted in the chart are not necessarily representative of actual prices

or where most of the generators are retail competitors (gentailers), the less competitive the retail market is. For example, in SA where there will only be three significant base load generators, the retail competition has fallen to perhaps the two main retailers widely active in the market - this is probably impacted by the fact that two of the base load generators are owned by the two dominant retailers in the region.

It is clear that for a vibrant retail function in SA it is important that the larger generators should be independent of significant retail activity so that those retailers without their own generation to back up their retail function, can have access to competitive generation hedges.

AGL, owner of largest thermal generator in the region (Torrens Island power stations A and B have a combined capacity of 1260 MW), is also the dominant retailer in SA. The second largest electricity retailer, Origin Energy, also owns Osborne PS.

This means second tier retailers either have to access base load hedges from Pelican Point (limited to one unit output and affiliated with retailer Simply Energy) or from one of the two largest retailers in the region. Whilst TIPS B (800 MW) is currently to remain in operation, AGL has forecast closure of TIPS A (460 MW) in 2017.

While, in theory, retailers can access capacity on the interconnectors through the interregional settlement residue auction process (and so "sort of" access base load hedges from Victoria), this mechanism does not provide sufficient certainty for retailers to provide firm contracts to end users.

Further, the wind generators are not able (or prepared) to offer firm hedges due to their intermittency in generation or ability to source electricity from sufficiently diverse locations to have a continuous supply.

As a result, there is limited retail competition to AGL and Origin and it has already been observed that there are at most only two retailers active in the SA regional market for larger users. Active competition in generation is required to support a robust retail market therefore having the bulk of generation controlled by the two dominant retailers will result in low retail competition in the region.

It is clear that the forward electricity prices are being driven by the scarcity of generation counterparties to provide firm and competitive base load hedge contracts for other retailers to be competitive.

2.8 The impacts of the way consumers access electricity supplies in SA

Whilst the vast majority of end users access their electricity supplies through formal firm retail contracts, because of the higher prices in the SA market, and it's greater spot price volatility compared to other regions, a significant number of end users in the SA region access their electricity supplies based on a spot price pass-through with their retailers.

The impact of this is, in proportion to the total demand in SA, there is a significant volume of electricity effectively sourced from the spot market by consumers. This also means that there will have to be a significant amount of generation provided to the spot market that is not balanced by a hedge between retailers and generators.

When there is a full hedge book for a generator, a generator is more likely to bid its output into the market at a low price in order to ensure that it is dispatched and so deliver electricity to meet its retail hedge contract. The less a generator is hedged to a retailer, the greater is its freedom to set its prices and exercise market power if it has this.

What has been observed in competitive electricity markets is that when a generator has a significant amount of its output unhedged and when it has market power, the generator is incentivised to bid its output at very high prices because this provides a high reward for the amount of output that is not contracted. Equally, the amount that is contracted is effectively not subject to the high price so the generator is not at risk for its contracted volume.

When these two aspects are considered together, (ie a high proportion of electricity supplied from the spot market and a generator with market power), the greater the likelihood there is for the generator to exercise that market power.

Those consumers accessing their electricity supplies from a standard retail arrangement will see their prices rise as their current retail contracts expire and are replaced by new contracts based on the new generation costs which have been signalled by the futures market. As noted above, these contracts will be basically developed from firm hedges provided by SA regional generators as the ability to access firm hedges from the wind farms and interconnectors is difficult. Further, as the impact of any exercise of market power translates into spot prices, so too will the spot market drive the futures prices and ultimately the retail prices.

Those consumers exposed to the spot market will benefit from lower spot prices when wind farms are operating and from flows on the interconnectors but equally they will be exposed to the spikes in prices seen when wind generation is low and there is instability in the market. Of greater concern is that those exposed to the spot market will see immediately any outcomes from the exercise of market power.

While there have been occasions where the wind output exceeds the regional demand[23], for much of the time[24] there will be a need for regional generation to provide the additional electricity needed to balance the market. It is at these times that the remaining base load generators (especially TIPS B which is the largest generator) will have market power.

2.9 Other changes and impacts forecast

As an offset to the loss from the thermal generation closures, the upgrade of the Heywood interconnector and ElectraNet proposals to relieve some constraints in the transmission network through its Network Constraint Incentive Parameter Action Plan (NCIPAP) process will increase supply in the SA region. But the net increase in supply will, at best, only provide for the loss of unit 2 at Pelican Point.

[23] With the increases in forecast roof top solar PV and wind farms these occasions will increase in number
[24] Especially when the wind drops and there is insufficient capacity on the interconnectors

Equally, AEMO is forecasting that roof top solar PV will increase significantly. AEMO comments[25]:

> "Under low demand conditions, AEMO's 2015 National Energy Forecasting Report (NEFR) shows that, based on continued uptake of rooftop PV and its contribution to supply in South Australia, rooftop PV may offset 100% of operational minimum demand, during midday periods, by 2023–24. This increases the need for export from South Australia to Victoria during these periods. It should also be noted that the changing generation mix may have operational impacts on the Heywood interconnector with its upgraded capacity. Ongoing work is:
>
> - Understanding the range of technical issues associated with managing the power system with little or no synchronous generation on-line.
> - Developing the tools and models to analyse performance of a power system with little or no synchronous generation on-line.
> - Investigating the existing fleet of rooftop PV inverters and their response to frequency and voltage disturbances.
> - Investigating the impact of high levels of rooftop PV penetration in South Australia on the operation of the Under Frequency Load Shedding scheme in the state."

AEMO is also forecasting significant growth in wind farm output with wind farm output tripling in the next 10 years.

However, when the wind farms are providing supply at their highest output and the interconnectors are a full capacity, the SA regional demand will still require some thermal generation to provide supply at times when the wind drops and/or at night when rooftop PV is not supplying.

2.10 System control

In addition to the net amount of generation, there is a need for the demand to be able to increase incrementally/decrementally in order to maintain the electricity supply frequency at 50 Hz. This increase/decrease capability (called frequency control ancillary service or FCAS) needs to be provided quite quickly in order to maintain system frequency[26] and needs to have generation that can be dispatched on demand when frequency is low. While some wind farms can reduce output on request (ie reduce supply) when the frequency is above 50 Hz (and thereby reduce the frequency through providing less supply), raising frequency can only be achieved by actual increase in supply or by load shedding (ie by asking users to reduce their demand). Only thermal

[25] Page 3 The Heywood interconnector: overview of the upgrade and current status, August 2015, available http://www.aemo.com.au/Electricity/Planning/South-Australian-Advisory-Functions/Heywood-Interconnector-Update

[26] FCAS is through automatic frequency adjustment (regulation FCAS), fast raise/lower in 6 seconds, slow raise/lower in 60 seconds and delayed raise/lower in 5 minutes. Even fast start generators (such as gas turbines) cannot start and get synchronised within 60 seconds. See http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services for a description of ancillary services.

generation can provide additional generation on demand when system frequency falls (ie boost supply at call).

With the closure of Northern Power Station, the suppliers of frequency control lie with those generators in the region and the interconnectors; for the very fast responses needed for the FCAS supplies, only generation which is already dispatched can respond fast enough to maintain frequency.

Setting the regional frequency can only be achieved through the Heywood interconnector or from regional controllable (thermal) generation. While the Heywood interconnector is a double circuit supply (ie has redundancy), both circuits are mounted on the same towers and run between Ausnet Services' substation at Heywood near Portland in Victoria and ElectraNet's South East substation near Mt Gambier in South Australia. For most conditions, this provides a secure supply from Victoria, but in the event of a bushfire, it is possible that both circuits might have to be disabled[27], resulting in SA region being "islanded"[28]. When islanded, SA region needs its own thermal generation to set the regional frequency.

This issue has been identified by AEMO and it has implemented actions to minimise this risk.

[27] The power line route between Heywood and South East substations traverses areas where grass fires and/or bushfires can occur

[28] Later in the report, it is suggested that increased interconnection could be a solution. The suggested option is to build a new interconnector between Krongart in SA to Heywood in Victoria. This would mean that the bushfire risk would not be mitigated significantly

3. Where to from here?

3.1 A summary of the SA market

The intent of the RET is to decarbonise the electricity market and, in theory, this should happen with lower prices for electricity[29].

But in SA where the highest proportion of renewable electricity is occurring (relative to the regional demand), the lower prices do not seem to happen. What we are seeing in the SA market is:

- A market which has significant ~450 MW of solar generation in the middle of the day with expectations that it will nearly triple in size over the next decade
- A large amount of wind generation wind generation (~1000MW) which has an availability of ~35%, with an expectation that this will this will double over the next decade
- A near halving of the volume of electricity sales by thermal generation since 2008 to 2015, which has resulted in the planned and actual closures of more than 1000MW of thermal generation from mid 2016 (Playford and Northern stations and unit 2 Pelican Point) with the prospect of another 460MW (TIPS A) a year later
- An upgrade of Heywood interconnector and the potential of less constrained flows on Heywood and Murraylink interconnectors through network de-bottlenecking
- Significantly more volatility in the market than seen in markets with a greater proportion of thermal generation because of the price impacts from disturbances at times of low wind generation
- A doubling of gas prices which impact all of SA's remaining thermal generation after the closure of Playford and Northern power stations
- An increasing concern with the stability of the SA power supply (frequency control), especially with the risk of Heywood being shut down or capacity limited

The MEU notes that the above market conditions are driving electricity prices in the SA market higher, with little hope for relief. The market arrangements in their current form will only lead to greater volatility, increased power of the dominant gentailers, and place a long term burden on all electricity consumers in SA.

However, increasing the amount of renewable generation in other regions of the NEM could ultimately lead to a similar situation seen in the SA region, so the solutions identified for the SA region should have application in other regions as the need arises.

[29] See appendix 3, for example, and the Warburton report mentioned above

3.2 Sharing the benefits of low cost electricity

It is noted that the high forecast prices in the futures market (of >$80/MWh) and, as seen in section 2.6 above, reflect the cost of generating incurred by the regional generators; similar prices are being offered by retailers to end users. Despite this, perhaps some 70-80%[30] of the total electricity supplied in SA from the market is derived from sources with a much lower cost structure (ie the roof top solar PV, wind farms and the interconnectors) than those supplying the firm base load hedges (ie TIPS B, Osborne and Pelican Point).

This raises a concern that, if consumers are not receiving the benefits of the lower cost supplies, where do the benefits of having the lower cost supplies go?

In theory, those sourcing electricity from the market can benefit from these lower cost supplies and when the lower cost supplies are fully utilised, the balance is sought from higher cost suppliers. Again, in theory, retailers would share the benefits of the lower cost supplies with their customers on the basis that the final costs would reflect a mix of lower cost supplies in proportion with the higher cost supplies.

Assuming that wind farms need a price of about $40/MWh (a futures price seen in the Victorian market) to add to their RET revenue to cover their total costs, and the flows from Victoria (also at $40/MWh) then perhaps 75% of the electricity needed by SA consumers will be supplied at $40/MW and the balance at $85/MWh giving an average price of about $51/MWh. Yet, currently, a full base load hedge is offered at 70% above this price. So who benefits from the premium? Certainly not consumers.

If the forecast of a doubling of the amount of wind farms eventuates, then wind farms and the interconnector would provide all of the demand from the market[31] giving a notional cost at the same level as provided in Victoria.

However, the market does not operate this way - the market sells electricity at the price offered by the last dispatched generator so that the price never reflects a cost build up based on the prices each generator is prepared to sell at for its output.

A retailer sources its supplies for on-selling from regional generators or from the regional spot market as it cannot take the risk of sourcing supplies across an interconnector. To minimise its risks, a retailer gets a portfolio of firm hedges from those regional generators able to provide firm supply[32] with a minimum sourced from the spot market. Effectively this approach means that it is generators able to provide firm hedges (ie thermal generators) that will benefit from the supplies of low cost electricity delivered into the market.

So consumers that source their electricity supplies from retailers on firm contracts do not benefit from the low cost supplies that wind farms and the interconnectors provide.

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[30] This based on the total demand in 2015 for the SA market of ~12,250 GWh, 3223 GWh from wind farms and a maximum of 5700 GWh on the Heywood interconnector when operating at 650 MW plus potential flows on Murraylink

[31] This also assumes that the forecast threefold increase in roof top solar PV keeps the regional consumption of electricity at the same level as in 2015

[32] Noting that wind farms are not able or prepared to provide firm hedges

There are some consumers that effectively source their supplies from the spot market (most commonly via a spot market pass through arrangement with a retailer). In theory, these consumers can benefit from the lower cost supplies that are provided to the market from the wind farms and the interconnectors at the times when these are sufficient for the regional demand. When the interconnectors fail (or when it is constrained) and there is insufficient wind generation[33] then regional thermal generators are dispatched and, in theory, they will offer prices reflecting their SRMC.

If there is insufficient competition between base load and intermediate generators, then the spot prices can be set at excessively high levels, many times that of the SRMC.

Therefore, consumers that source their electricity supplies from the spot market can get the benefit of the low cost generation but are exposed to the potential for very high costs if there is insufficient competition.

In SA, as discussed in section 2, there is insufficient competition in base load and intermediate generation, and AGL's TIPS B has to be dispatched for considerable periods of time regardless of what else is dispatched. This means that for significant periods of time there is a substantial risk that the spot market will exhibit prices resulting from the exercise of market power.

3.3 The core issues

The core issue facing consumers in SA region is high forecast prices, well in excess of those in other regions[34] and demonstrated by the futures markets (see section 1). These high prices are an outcome of a number of different causes and the key findings are:

- The market is exhibiting increased volatility and the high proportion of intermittent generation in the SA market is increasing this volatility; increased volatility increases electricity prices to consumers
- The high price for gas is increasing current and futures prices of electricity, but the current level of prices seen is reflective of this high price of gas
- Renewable generation is displacing volume from thermal generation causing thermal generation an inability to recover its fixed costs leading to closures of thermal generation. These closures are in turn creating the potential for exercise of generator market power
- Forecast growth of intermittent generation is likely to create a condition where, in the absence of commercial storage options, there will be insufficient capacity to export surplus generation

Underpinning these core problems, there are a number of other issues which impact the core issue:

- An inability to benefit from lower regional prices from wind and interconnectors

[33] Wind farms have a typical load factor of 25-40% depending on location. In SA in 2015, wind farm load factor was ~35% which is considered quite high in comparative terms
[34] Yet the futures market prices are consistent with expected gas prices and the heat rates of TIPS B, Osborne and Pelican Point base load generators which would set the regional hedge prices.

- Reduced retail competition through lower competition among generators
- Increasing risk of loss of supply through insufficient generation being available
- System frequency instability risks

There are a number of solutions that have been proposed by various proponents to address the SA issues, but a key issue for SA consumers (industrial, commercial and residential) is there is a need for lower electricity prices than currently are available. These solutions include:

1. Increasing generation. This would increase competition in the supply of electricity
2. Increasing interconnection. This would reduce volatility, allow greater access to Victorian prices and allow expected future renewable generation to be exported in the volumes expected
3. Combining SA and Victorian regions into one. This would allow SA consumers to access Victorian prices
4. Improving the ability to trade across an interconnector. This would allow SA consumers to access Victorian prices
5. Paying for electricity as bid. This would allow SA consumers to access Victorian prices and prices directly from wind farms
6. Paying for capacity and spinning reserve to be available and paying for volume at cost (eg RERT, specific availability payments, capacity market, etc). This would increase competition among generators
7. Limiting the exercise of generator market power. This would keep prices closer to SRMC generation prices
8. Increasing storage (eg batteries, chemical, pumped, etc). This would provide intermittent generation to provide firm hedges.

A further option is that gas prices should be reduced as this would reduce the SRMC of generation. This is the focus of reviews by the AEMC and the ACCC and is not considered by this report.

The eight options are discussed in greater depth, below. However, while the MEU considers these provide the best solutions from a range of options available and provide a sound basis for further evaluation, this listing should not considered to be exhaustive, as other stakeholders not involved in this stage of the process might have additional options that could/should be considered.

In the next stage of the assessment, the MEU will seek input from a wider range of stakeholders which may lead to other options which could assist in resolving the core problem of high prices.

It is important to note that all options proposed within this paper come with risks and opportunities, both of which are discussed in the relevant sections. This section of the report does not provide a firm indication on the best solution going forward. Rather, this section provides insights into options available and the likely benefits and detriments of each option.

Further, it is accepted there will be political sensitivities surrounding some of these options. The MEU has aimed, wherever possible, to remain neutral in its assessments in order to remain objective. The next stage of the assessment will have to identify these political realities and provide solutions that address these realities.

3.4 Proposed Solutions

3.4.1 Increased generation

The problem facing consumers is the loss of base load generation, driven primarily by a loss of sufficient volume to cover the fixed costs of the generators. The AEMO 2015 ESoO forecasts the following additions to the SA generation fleet:

- 150 MW of combined cycle gas turbines. This is unlikely to occur while Pelican Point has Unit 2 closed and is forecasting a wind back of output from unit 1. With more wind farms forecast to be added, this will displace even more baseload generation. So while the option is possible, it is unlikely to occur in the short to medium term and unlikely to occur before Pelican Point returns to operating at full output.
- 570 MW of new open cycle gas turbines. While the addition of open cycle gas turbines will help overcome the reliability issue, the cost from these will compare very unfavourably to the cost of electricity from Victoria. The addition of these plants will assist at times in meeting the peak demand in the region, but it is important to note that the cost of electricity from such generation will be significant - probably in excess of $300/MWh - to recover both capital costs and operating costs[35]. Thus, while additional open cycle gas turbines will provide improved reliability, they are a very expensive option.
- 50 MW of large scale solar. There are forecasts for large scale solar plants with heat storage available which will provide some potential for solar base load generation. However, such plants are still at the pilot stage. While these offer potential in the long term, it is important to recognise that the SA average demand is likely to remain at >1500 MW and peaking at >2800 MW, levels which are currently being observed. For these new solar options to provide sufficient output to meet the SA base load demand for electricity in the short to medium term is unlikely. Further, while large scale solar is proven technology elsewhere in the world, it is expensive[36].
- 510 MW geothermal. Geothermal has the ability to provide base load power without associated storage and would be a good addition to the SA generation base. Geothermal is proven technology in other parts of the world, but it is as yet unproven in the NEM and there are at least two developers that have been attempting to bring the operation of their pilot plants to commercial viability. What is also not readily recognised is that the

[35] For example, the most efficient open cycle gas turbine plant will incur costs for gas alone of about $70/MWh based on gas at $7/GJ delivered, and when capital costs are added, the cost will be nearly $250/MWh when operating for the SA average period for OCGT plant of ~400 hours a year

[36] For example, the Solar Reserve solar/thermal plant in Nevada (110 MW) will generate electricity at about $US137/MWh ($A180/MWh) with subsidies, although other plants being contemplated will have lower costs (see http://reneweconomy.com.au/2015/worlds-biggest-solar-tower-storage-plant-to-begin-generation-this-month-22860)

best geothermal sites in SA are remote from the ElectraNet transmission system and there will be a significant cost to connect those geothermal sites currently being developed to the NEM.

There appear to be a number of concerns regarding additional generation.

Firstly, that thermal generation is already withdrawing from the SA regional market due to being displaced by renewable generation which raises the concern as to why new thermal generation might want to compete with more renewable generation.

Secondly, the high cost of new thermal generation due to the high cost of fuel (gas) is a barrier to new thermal generation and will raise electricity prices for consumers higher than those currently being seen.

Thirdly, other than wind and roof top solar PV, the options for other renewable generation are significantly higher than the cost of power from Victorian generators. While the RET scheme provides sufficient subsidy to wind and roof top solar PV to make these options commercially comparable to thermal generation[37], the subsidies are probably insufficient to match the price from other forms of renewable generation. It also needs to be recognised that the RET scheme is to reach its target level by 2020. For further renewables to be subsidised beyond 2020, this will require a change in Federal legislation[38].

MEU analysis indicates that stimulating increased generation does pose a significant challenge. Although our analysis indicates that due to increased market power held by TIPS B and the exit of generators outlined above, this indicates there exists little incentive for new entrant generators to enter the SA region. However, the MEU notes that there is work being undertaken on the development of other renewable generation plant within SA, but we view these as providing a limited solution for the long term. (See also section 3.4.8)

3.4.2 Increased interconnection

At a high level, increased interconnection provides two main benefits. Firstly it will allow greater flows of low cost thermal generation into SA from another region when required and so keep prices for electricity at similar levels to those seen in Victoria.

Secondly, it will allow greater flows of renewable generation from SA to another region, ensuring the maximum utilisation of all of the renewable generation in the region. For example, if the amount of roof top solar PV increases as forecast, this will limit the amount of generation that is needed to meet the SA regional demand. Already the amount of wind generation is sufficient to nearly meet the SA regional demand on many occasions. A doubling of wind generation implies that there will be an additional 1000-1500 MW of wind generation[39] provided and the SA regional consumption will not be able to absorb this, thereby requiring an ability to export this surplus to

[37] That is, roof top solar PV is comparable in price when adding the savings from reduced network costs
[38] I is not Coalition party policy to extend the RET and while the Federal Labor party has signalled an increase in renewables, it is not apparent whether the subsidies would continue or if they do, at what level.
[39] It needs to be remembered that the RET is to reach its capacity by 2020, (ie in 3.5 years which is the medium term for the purposes of this report) and to get the maximum benefit, this renewable generation needs to be in place by 2020 or earlier.

another region (eg Victoria). By mid 2016, the capacity of Heywood interconnector will be nominally 650 MW. In theory Murraylink can transfer 200 MW but this is frequently constrained (especially at times of high demand) due to constraints in the ElectraNet and Ausnet transmission networks[40].

With 650 MW eastward flow capacity on Heywood and at most another 200 MW eastward flow on Murraylink, there will still be renewable generation that cannot exit the region. Some augmentation of the interconnectors is required to ensure the benefit to the NEM of renewable generation in SA is maximised.

Increasing the capacity of an interconnector requires an extensive process[41] and requires a net market benefit to be identified before augmentation can be implemented. A net market benefit does not include any consumer benefits that might occur such as lower regional prices. The argument posited to support such a decision is that costs to consumers from high priced regional generation is "a transfer of wealth" and therefore is not a benefit to the market as a whole. Consumers find this argument difficult to accept when it is considered that it is consumers that fund any interconnector augmentation through the network charges they are required to pay[42].

Whilst increased interconnection would assist the market as a whole (through providing better access to ex-region generation) to support spinning reserve and providing alternative sources of market support (eg ancillary services), unless the augmentation provides for the full capacity of the SA regional demand, then there is still the residual risk that regional generators will set the regional price at very high levels.

Without a change in the benefits test (such as allowing consumer benefits to be included) such a major increase in augmentation would appear to be unlikely.

For example, as part of the augmentation studies for the Heywood upgrade, ElectraNet and AEMO modelled a number of nominal 2000 MW augmentations[43] - two main options connecting SA to NSW and one connecting into Victoria. These main options are shown geographically in the following figure 1 from the ElectraNet/AEMO Joint Feasibility Study.

[40] These constraints mean that not infrequently Murraylink operates "counter price" with flow to SA on Heywood and flow from SA on Murraylink

[41] See for example the recent process used to justify the augmentation of the Heywood interconnector where activities commenced in mid 2010 and the work is due for full operation in mid 2016

[42] Generators only have to pay for the network elements they use to access the shared network.

[43] ElectraNet-AEMO Joint Feasibility Study, South Australian Interconnector Feasibility Study February 2011 available at http://www.electranet.com.au/assets/Uploads/interconnectorfeasibilitystudyfinalreport.pdf

Figure 1 New high-capacity augmentation options

Each of the options was modelled under a number of scenarios but no options for connection to NSW under any scenario provided a net market benefit whereas the 2000 MW connection from Krongart to Heywood in Victoria showed a net benefit under some scenarios, but not until the late 2020s.

Subsequent to the Joint Study, a benefits test (RIT-T) was undertaken for the current Heywood upgrade[44] which showed that the 2000 MW to Victoria provided a net market benefit but less than the current upgrade project. If the consumer benefit was added to the market benefit, it is clear that a new 2000 MW interconnector to Victoria (option 3 Krongart to Heywood) would address the problem currently seen.

Among the assumptions made for the RIT-T for the current upgrade were:

- Average growth in energy consumption and peak demand of about 1% pa (2012 NEFR medium scenario)
- Assumed scheduled (ie thermal) generation summer capacity of 3232 MW to 2012-22 (2012 ESoO)
- A potential reserve deficit of 24 MW in 2019/20 (2012 ESoO medium scenario)
- A investment in new generation might be deferred as a result of the increased interconnection
- Playford PS would convert to an open cycle gas turbine generator (ie would be available in the future)
- FCAS costs were not material

44 Available at http://www.electranet.com.au/assets/RIT-T/SA-Vic-Interconnector-Upgrade/10344-SAVicInterconnector-PACR-Jan2013.pdf

- Continuation of a carbon price
- Potential loss of supply was imminent

What was not built into the assumptions was that the burgeoning wind and roof top solar PV generation would displace significant amounts of thermal generation making them less commercially viable and that this would cause up to 1250 MW of thermal generation plant (especially base load) to exit the SA market.

The MEU considers that the RIT-T needs to be recalculated using more up to date information in order to assess whether the Krongart-Heywood 2000 MW option delivers a larger net benefit than assessed before, allowing that the current upgrade will be operational. Such a recalculation would have built into it the new forecasts for renewable energy growth in the SA region. If wind farm capacity doubles and roof top solar PV triples[45] then the combined output of the roof top solar PV and wind will exceed 4000 MW of which 40% might be used regionally with the balance being exported to Victoria. The capacity of the upgraded Heywood and Murraylink interconnectors will be not be sufficient to export the full amount of regional renewable generation, requiring increased interconnector capacity for the exports and to maintain frequency stability.

The MEU also recognises that even if work was commenced immediately in constructing a 2000 MW interconnector, this option is unlikely to be available within 3 years and could well take longer.

There is the risk that an investment in increasing interconnector capacity would impose a long term liability for consumers. This is a real risk as network assets such as an interconnector have a life of 50 years or more and, based on preliminary estimates of the cost of such a new large interconnection, the additional cost to consumers would be $4-5/MWh based on current levels of consumption in SA drawn from the market. Without increased interconnection, there remains the electricity cost premiums inherent in the higher price of gas, the potential for exercise of market power and the need for increased investment in thermal generation to provide the reliability expected. For example, if electricity was available from Victoria at $40/MWh as now, then the cost of power from Victoria would be $45/MWh when the cost of the new interconnector is added. In contrast, the cost of power implied by the futures market for 2018 (eg 7 March 2016 as in section 1) is $90/MWh and in 2019 is $64/MWh, providing a clear benefit for SA consumers even with paying for the cost of the interconnector.

It is important to note that other options (such as new generation and/or storage) will also require significant capital investment and so all options have to be compared.

3.4.3 Combining Victorian and SA regions

The benefit of this concept is that spot market prices would be more stable and that retailers could access hedges for the SA region from Victorian generators. This would allow consumers to benefit from the lower costs from Victorian generators. This would also remove some market volatility from the SA region as the amount of wind generation for the combined region would not

[45] See AEMO ESoO 2015

lead to wind dispatch matching the regional demand (or exceeding it when more wind farms are added) and therefore always reflect the price offered by thermal generation.

While the concept provides a benefit to SA consumers as lower cost hedges can be accessed for SA consumers, it increases the risks to Victorian consumers. This is because there will still be a limit of the flows on the Heywood network element of the combined region and that there would be times when the spot price in the combined region would reflect the out of merit order dispatch of thermal generation on the SA side of a constrained network[46] due to the network constraints.

Such an option would be more viable should the 2000 MW upgrade of interconnection be implemented. While the risk in the SA market would be less under the 2000 MW interconnection, there is still value in assessing the benefits of combining the regions as the amount of wind generation in the SA region would provide a benefit to Victorian consumers as would access by SA consumers to the low cost generation from Victoria.

The MEU considers that, although this option has some merit, the combined region option is not viable unless there is much stronger interconnection between the regions.

3.4.4 Improving the ability to trade across the interconnector

When electricity flows from one region to another, the generator in the exporting region is paid at the exporting regional price and the user in the importing region pays at the importing regional prices. When there is a differential in the prices this must be accounted for. This differential can be a significant amount in the market but is not known until ex post therefore offering prices in one region based on prices available in an adjacent region is speculative and financially risky.

Under the current rules to adjust for the money that is caused by this differential, there is an auction process where Participants bid ex ante for rights to the differential through the Inter-Regional Settlement Residue (IRSR) auction process. The proceeds of the auction and any residue not so purchased are allocated to consumers through the importing region's transmission network where the post auction residue is included in the transmission pricing for the following year.

The theory behind the process is that a retailer can notionally buy the rights to some or all of the flow from the exporting region at the exporting region's price. In practice, the process is complex, not very efficient and does not provide sufficient support to effectively contract across the interconnector. This shortcoming was recognised in the AEMC Transmission Frameworks Review where the First Interim Report states[47]:

> "*The IRSR does not, however, provide a perfect hedge for inter-regional basis risk.*"

Because of the risks involved, auction prices are unlikely to provide full value for the price differential and therefore much of the benefit of the price differential is transferred to the

[46] This problem has been seen frequently in the Queensland region where there is a strong argument that network constraints and generation locations imply that Queensland region should be two or three regions. That this has not occurred is a political decision.
[47] AEMC First Interim Report Transmission Frameworks Review 17 November 2011, Box 7.2

Participant purchasing the IRSR rather than consumers. While there is ultimate clearance of the IRSR, it does not necessarily return to consumers the benefit of the lower costs of imports.

The Optional Firm Access (OFA) process proposed for providing firm access by generators to the shared network potentially provides a basis for providing a Participant with firm access rights on an interconnector but the OFA process has not been developed yet to provide such an option.

Even if firm access could be bought on an interconnector, this still would not provide sufficient capacity for all SA consumers to benefit from the low prices available from the Victorian region and any benefit would probably stay with the Participant that purchased the firm capacity.

A rule change to vary the IRSR process to pass the benefits directly to consumers rather than through Participants is unlikely to be achieved in less than two years.

3.4.5 Pay as bid

The concept behind Pay as Bid is that retailers and consumers would only pay the actual prices bid from each source of generation and reflects the views posited in section 3.2. The main benefit from this approach is that consumers benefit from the lower costs sought for the bulk of the electricity supplied, rather than paying a premium over the amounts that are offered from paying lower priced generators the same price as that bid by the last generator dispatched.

A pay as bid approach particularly is important where so much of the electricity coming into the SA region comes from imports from Victoria which are generally at a much lower average price than supplies provided by thermal generators within the region[48]. While there are methods for addressing the price differential on interconnectors these do not provide an obvious benefit to consumers and the premium (a benefit) is taken by Participants. While there may be some of the benefit passed onto consumers, there is no certainty that this occurs. It is inefficient to charge SA consumers a premium for their electricity supplies over the cost of the imports, especially when a proportion of the price differential is taken by Participants and not returned to consumers.

A Pay as Bid approach potentially increases risks for consumers as it could provide a basis for "ratcheting" of bids from generators, although generators that have provided hedges to retailers would still be incentivised to bid at levels below their hedge prices to ensure they are not exposed to prices higher than their hedge contracts if they are not dispatched. Equally, a pay as bid approach reduces the impact of market dominance and the associated exercise of market power.

A Pay as Bid process would require a significant change to the market structure and rules and is unlikely to be a solution within three years.

[48] Wind farms also bid prices very low but the value of the low prices does not go to consumers except those in the spot market when wind farms output equal or exceed the regional demand

3.4.6 Payments for capacity

Generators have a high fixed cost to provide the capital for the generation plant. Such fixed costs vary from those for open cycle gas turbines (~$900/MW) through to coal fired generation ($3000-4000/MW depending on coal type and boiler type). Generally the smaller the plant, the higher the capital cost per MW.

Regardless of how much output is provided, there is still a need for generators to get a return on the capital cost of the generation plant provided as well a return of the capital invested. Under the energy only market design used in the NEM, there is no direct return on and of capital and the generator must recover these fixed costs within the price offered per unit of volume sold (ie MWh). This increases the risk to the generator that it will not recover its capital related costs because if it bids high to recover the costs, it might not get dispatched and have no sales to get any return and if it bids low then it might not recover its fixed costs.

In contrast to the energy only market used in the NEM, many other jurisdictions provide for a payment to generators to be available; such a payment is not made if, when called, the generator does not provide supply. These markets are called capacity markets - the Western Australian electricity market (WEM) is a capacity market. Some electricity markets previously established as energy only markets have converted to capacity markets but few if any capacity markets have converted to energy only markets[49].

This research is not to debate the merits and demerits of the two approaches but to highlight that the generators in SA region have decided to close operations because they are not making sufficient revenue to cover their capital costs due to insufficient sales under an energy only market structure. One way of overcoming this would be to pay these generators to be available as and when needed through covering part or all of their fixed costs.

In the absence of a conversion to a capacity market, as the NEM is not structured to make payments for being available, then to introduce reimbursement for being available would have to be provided as an "off market" payment. Such an off market payment could be achieved through a payment from government, funded perhaps by a levy on electricity consumers[50] or using the Reliability and Emergency Reserve Trader (RERT) facility already built into the market structure - the RERT has provision for AEMO to pass the costs incurred in arranging for parties to provide support to the market.

The RERT process could be implemented immediately and then be followed up by an off market arrangement to provide capacity.

It is unlikely that a move to a capacity market could be implemented within less than three years.

[49] The reason for this may be related to a view held by many eminent energy market economists that with energy only markets there is "black hole money" required to balance the costs incurred by generators. They assert that this black hole money has to be recovered through the exercise of market power which distorts the market

[50] A levy is used in Victoria to pay for the subsidised electricity provided to Alcoa at Portland, so a precedent has been made for off-market payments to generators. The levy is sourced from transmission charges

3.4.7 Limit the exercise of market power

The MEU maintains its position that there needs to be a market rule to limit the exercise of market power, similar to those used in overseas jurisdictions. However, it is recognised that the process initiated by the MEU in 2010 did not result in a rule change but did result in a recommendation for the AER to have greater market monitoring powers.

There is currently a change in the electricity law proposed by the CoAG Energy Council (CEC) to introduce an explicit wholesale market monitoring function for the Australian Energy Regulator (AER)[51]. The MEU has noted a few shortcomings in the proposed change and is concerned that even if the AER does identify incidents of exercise of market power, it has no ability to redress any problem.

With the reduction of competition[52] due to the closures, there is little doubt that, as discussed in section 2 above, the structure in the SA region is now ideally suited for the exercise of market power, particularly when TIPS B must be dispatched for significant periods of time. This change in dynamic is a direct outcome of the increase of renewable generation in the SA region.

The MEU considers that the issue of market power needs to be readdressed because what is being seen in SA region now will be seen in due course into other regions as the amount of renewable generation increases in the next few years, and more thermal generation is displaced.

3.4.8 Increased storage

A major problem with intermittent generation is that the energy is not available at all times. If the energy generated when the intermittent generation is operated could be stored for use when it is not operating, then many of the problems faced would be minimised. It is for this reason that wind farms coupled to pumped hydro generation provides a neat solution to providing reliability of supply.

In the SA region, there is little access to existing pumped hydro generation and this access is limited to the capacity of the interconnectors to Victorian and from there to other regions. Augmentation of interconnection would allow some access to pumped hydro storage in the Snowy and Tasmania but this is unlikely to be sufficient for the needs of SA region.

Residential battery storage is a potential solution for gaining greater benefit from roof top solar PV but currently the costs are seen as too high, although if these costs continue to fall, this option could be more viable in the near future. However, this solution will not address the main concern for storage on a transmission network scale.

The current forecast is that renewable (wind) generation will double. This means that at times >3000 MW in SA could be generated from wind farms yet the average SA regional demand is about half this. As wind generation has a load factor of about 35%, this means that storage

[51] CoAG Energy Council Reform Agenda Implementation Plan – Progress Report Issue Date: 23 July 2015
[52] Based on the amount of base load and intermediate generation now expected and much less competition than in 2008-2010 which initiated the MEU rule change proposal

would have to have a capacity of notionally twice the regional demand so that electricity is available at all times. A review of wind generation patterns implies that the period between high wind outputs can last up to four days, this means that at an average demand of 1500 MW and with the main source of power comes from wind farms, the storage would have to hold 50-70 GWh of electricity assuming that the interconnectors operate at full capacity. Further, even with a doubling of wind farm generation, this will still not meet the entire electricity needs of the region so even if a storage option was viable, there is still a need for interconnection for:

- setting the regional frequency
- providing system restart ancillary service (SRAS)
- imports of energy
- meeting regional peak demands

There are a number of other proposals for providing storage (eg, large batteries, through chemical storage where a chemical such as hydrogen is generated from electricity and is later used to generate electricity, etc) but the costs for such are still at uneconomical levels although they might in the future be commercially viable. For example, the US Department of Energy has a program for enabling energy storage for grid sized usage[53]. Its long term aim is to provide large storage facilities for electricity supplies at a capital cost of less than $US150/kWh[54] ($A200/kWh). Assuming 50-70 GWh of storage is needed in SA, this long term target for storage costs equates to a ~$12 Bn capital investment for the amount of storage needed in the SA region. While these costs are likely to reduce over time, they appear to be expensive compared to other options.

Certainly these options are not likely to address the near and medium term needs of SA consumers.

3.5 Conclusions

There would appear to be three basic routes to solve the problem, viz, more investment (eg more generation, increased interconnection, storage), regulatory changes (merge the regions, limit market power, improve trading across interconnectors, pay as bid) and paying for availability (change RERT, a levy). Of these:

- **A new large interconnector would appear to be the lowest investment cost option but this option will take time to pass through the regulatory processes and the construction phase**
- Regulatory changes such as proposed have been considered in the past but no firm outcome achieved, with perhaps the limitation of the exercise of market power being marginally enhanced but the new approach is still unlegislated and unproven. The other options will require changes to the market and be probably contentious and so take 1-2 years to implement in the event they are accepted

[53] See for example http://www.sandia.gov/ess/docs/other/Grid_Energy_Storage_Dec_2013.pdf
[54] ibid, page 33

- Paying for availability has some hurdles to be overcome, but is probably the only short term option available considering the time that contentious rule changes take.

4. Suggested actions for consideration

The fundamental issue facing electricity consumers in SA is being able to source lower costs of electricity now and in the short and medium terms (whether via retailers or from the spot market) which reflect the costs of production (whether generated locally or imported). This requires sufficient competition in the market to obviate the potential for the exercise of market power.

The following suggestions are not exhaustive but provide a basis to commence approaches to assist in alleviating the high costs for power in the SA region. As the approaches progress, other options may become apparent and offer a better outcome for consumers.

The first step for implementing the process is to test the viability of the options considered. Once this identifies the best solutions to address the problems, an action plan must be developed to deliver each of the solutions identified. This action program will need to include targets for consideration for each of the proposed individual action plans.

Actions for short term remedies (to seek a remedy within 6-12 months)

Generators that are closing operations need to be encouraged to remain operational. This would probably require some compensation in regard to the fixed costs they face. Options for implementing this are the RERT or a government initiated levy where consumers pay for sufficient generation to remain available to supply sufficient competition in the SA regional market. The MEU sees that keeping Alinta's Northern Power Station operational is a potential option but recognises that coal supply issues might prevent this occurring. If it is impracticable to reactivate Northern Station, then GdF Suez Pelican Point Unit 2 could be considered for compensation to allow it to be available.

It is possible that this option might need to be in place for 2-4 years

The initial approaches would be to identify if the payments required to allow generators to be available provide a better outcome than business as usual

Subsequent actions would require consideration with the:

- CoAG Energy Council and/or AEMC to change the rules for accessing the RERT
- SA government for negotiating with generators to remain operational (particularly Northern Power Station and Pelican Point) and establishing a levy mechanism
- AER to allow for the levy mechanism to be implemented through the transmission network if the levy mechanism reflects that used in Victoria
- AER regarding their processes for monitoring the exercise of market power
- CoAG Energy Council regarding what must be done if there is exercise of market power being demonstrated

Other actions could include consideration of:

- Decouple gentailer dominance to allow second tier retailers better access to wholesale contracts
- Identify ways to enable wind farms to provide firm hedges

- Reduce the price for gas.

Actions for medium term remedies (to seek a remedy within 1-3 years)

The apparent best outcome would come from increased interconnection of some 2000 MW capacity with Victoria. This will remove the need for providing payments to keep generators available.

This will require initial discussions with:

- AEMO and ElectraNet to recast the 2000 MW interconnector proposal and to identify if the project provides a greater net benefit than identified in the 2013 RIT-T without including a consumer benefit.
- Review of the cost of increased interconnection with other options and business as usual

Subsequent consideration would be required by:

- AER to ensure the project gets approval under the RIT-T
- CoAG Energy Council and/or AEMC to address the RIT-T so that consumer benefits are included in an evaluation if needed.
- CoAG Energy Council and/or AEMC regarding a better solution for trade across interconnectors that delivers all of the benefits of lower cost imports to consumers rather than through intermediaries that might retain some or all of the benefits

The MEU has noted that these short and medium term concepts for solutions reflect what is currently seen in Germany which also has been aggressive in the expansion of renewable generation (particularly increasing wind generation and roof top solar PV like SA). The solutions developed in Germany are similar to that proposed by the MEU - a mix of capacity payments for generation coupled to increased interconnection[55].

In the long term (>3 years), there needs to be a solution that addresses the issues seen in SA region on a NEM wide basis. Such solutions might include a change from an energy only market to a capacity market, lower cost storage solutions, increased interconnection and/or pay as bid options.

At this stage the MEU is not recommending action for consideration of these areas as solutions may naturally occur over the given time span without the need for targeted consideration. Further, the current views of the political challenges and/or costs involved will not address the needs of electricity consumers in sufficient time.

The MEU does not see that its proposed short and medium term actions and solution concepts to address the immediate SA region problems would detract from any of the longer term solutions that might need to be implemented on a NEM wide basis.

[55] See http://www.europeangashub.com/custom/domain_1/extra_files/attach_597.pdf

5. Appendices

Appendix 1

The Advertiser July 5, 2014

“Pelican Point Power Station will cut more than half its generation capacity early next year, threatening jobs”

PAUL STARICK, CHIEF REPORTER

ONE of Adelaide’s two major power stations is operating at less than half capacity, imperilling jobs, because it cannot compete with subsidised alternative energy.

The $450 million Pelican Point Power Station will effectively mothball more than half of its generation capacity from early next year, putting at risk some of the Le Fevre Peninsula plant’s 38 jobs.

The gas-fired power station has been stung by a significant increase in the amount of subsidised wind and solar production, resulting in a continuing decline in wholesale electricity prices.

Ironically, demand for clean liquid natural gas has made coal-fired power plants cheaper to run — about $10 per megawatt hour compared to Pelican Point’s $40 per megawatt hour.

In a written statement to *The Advertiser*, plant operator GDF SUEZ Australia Energy said the 479MW power station would offer only 230MW to the national power market from early next year.

Operating at full capacity, the plant can produce about 25 per cent of the state’s electricity needs.

The company revealed the plant had been operating at only half capacity for more than a year.

The company also blames falling electricity demand because of a downturn in manufacturing and a 40 per cent increase in transmission links with Victoria from July next year for putting pressure on the plant.

GDF SUEZ Australia Energy group head, corporate affairs Jim Kouts said these factors combined to make full-scale production at Pelican Point unviable.

“We will continue to monitor the market and be prepared to return to full production when conditions improve,” he said.

The company declined to comment about the future of the plant’s 38 workers, although stressed closure was not being considered.

But some jobs are likely to be at risk and some people might have to relocate to the company’s other operations. It also runs the Victoria’s Hazelwood and Loy Yang B power stations.

Pelican Point was built in 1999 on the Port River, 20km northwest of the city and has been generating electricity continuously since November, 2000.

The company says it is one of Australia's most advanced, efficient and environmentally friendly power stations.

Pelican Point is jointly owned by the European GDF SUEZ group's Australian arm (72 per cent) and Japan's Mitsui group (28 per cent).

Adelaide's other major power station, the nearby AGL Torrens on Torrens Island, is the state's largest and the largest natural gas fired power station in Australia. It employs about 180 people.

Energy Supply Association of Australia general manager corporate affairs Andrew Dillon said the mothballing of Pelican Point was a worrying twist on a global energy market trend.

Gas-fired power stations were becoming prohibitively expensive to operate because of market demand falling due to alternative energy and the gas price.

"In Europe some new gas-fired stations are shutting down before they officially open and just after they open," he said.

Mr Dillon said extracting gas efficiently from New South Wales and Victoria was vital to maintain the domestic and overseas markets.

He said the continuing operation of individual gas-fired power stations, such as Torrens Island, depended on numerous factors, including the success of other plants operated by their owners.

Appendix 2

The Age February 5, 2016

"Will the future arrive in time to head off the emerging energy crisis?"

Brian Robins

Will the future arrive in time?

The markets are telling us 'no', at least in South Australia as the fallout from one of the great living experiments that no one saw coming is beginning to drive electricity prices through the roof. And as the lengthening line of proponents of renewable energy attests, the outcome of this live experiment may end up pointing the way for the rest of the country.

Thanks to some of the best 'wind' resources in Australia, South Australia has found itself at the cutting edge of the electricity industry world globally.

Unlike other countries in northern Europe which also boast a high level of renewable energy, South Australia doesn't have a surfeit of back-up via links to generators of other regions in the eastern States to help offset any shortfall in local generation at times of surging demand.

And its 'experiment' becomes all the more pointed at the end of March with the planned shutdown of another large tranche of coal-fired baseload power stations, this time the last of the state's coal-fired power stations. Baseload is just that: electricity generators which typically produce power 24/7 so that your electricity is supplied anytime of the day or night – irrespective of whether the wind is blowing or the sun shining.

Rising amounts of electricity generated from renewable energy has driven down the wholesale price which makes it increasingly difficult for the operators of baseload power stations to make money especially since the cost of renewable energy is next to nothing once it is built and plugged in.

In response, coal-fired power stations in South Australia are being shut down, with the end-March closure of Alinta's Northern and Playford B power stations, leaving AGL as the main supplier via its gas-fired power station, Torrens Island, while Origin Energy, EnergyAustralia and others which mostly operate so-called peaker power stations which are switched on for short periods, are able to take advantage of price surges in the wholesale market.

The trigger for the surge in prices in South Australia was the decision by Alinta to bring forward by twelve months the closure of the Northern and Playford B power stations. Not only will it cut local generation, but it has slashed trading volumes in electricity futures, propelling prices higher.

Some relief to supply concerns may come mid-year with a network upgrade which will boost the amount of electricity that can flow from Victoria, but that will still fall well short of filling the gap from any demand surge and the closure of older power stations.

"The upgrade to the interconnector will increase the energy flow but it doesn't solve the lack of supply of hedges. The problem is not the physical energy market," says David Rylah, the trading and pricing manager at Energy Action.

It operates a reverse auction site for electricity users to get some competitive tension among rival electricity retailers but has found prices for electricity supplied between 7am and 10pm surging as much as 50 per cent to $140-170 a megawatt hour from $90-110 over just the past few months in South Australia – a rise in prices that will trickle down eventually to all energy users, including households.

The lack of an effective hedging market in South Australia means electricity retailers are pricing their offers to take into account expected volatility in wholesales prices, which is part and parcel of the electricity market.

And that surge in prices being experienced ahead of the shutdown of Alinta's coal-fired capacity has warnings of a shortage in electricity supply in South Australia within the next 12 months – basically, as soon as demand recovers from the slowdown next Christmas, according to forward estimates by the Australian Energy Markets Operator.

For large, energy-intensive users, sustaining operations in South Australia is becoming increasingly difficult since there is little impetus to lower electricity prices without embracing new technology such as battery storage. This technology, which allows the large-scale storage of energy is not yet competitive, but if high prices prove to be sustained, this may increasingly be the option pursued by many large energy consumers.

So rather than battery storage prices declining sufficiently to generate their take-up, which is expected in parts of Victoria and NSW, electricity prices in South Australia may rise to levels making the switch to this new technology look increasingly attractive.

Appendix 3

"SOLUTIONS FOR THE TRANSITION OF THE SOUTH AUSTRALIAN ELECTRICITY SYSTEM"

BRIEFING PAPER, CLEAN ENERGY COUNCIL, FEBRUARY 2016

South Australia is leading the nation in the uptake of renewable energy and now generates about 40 per cent of its electricity from solar and wind. The South Australian Government has played a leadership role in achieving this, and we encourage South Australia to continue strong support of climate change action and renewable energy deployment.

Although South Australia has already achieved a significant change in its mix of power generation technologies, the reliability of its power system remains excellent. Even with the state's two remaining coal-fired power generators shutting down next year, the Australian Electricity Market Operator has stated that the system will meet its reliability standards over the medium term – meaning at least 99.98 per cent of power demand will be served, as is the case with all other states in the National Electricity Market.

A significant proportion of Australia's coal generation fleet is operating beyond its designed life expectancy. The closure of these generators is an inevitable consequence of the decarbonisation and modernisation of Australia's electricity supply.

While policymakers and regulators have universally underestimated the rollout of renewable energy to date, South Australia has shown that these new technologies can be deployed faster and at lower cost than expected, delivering a massive economic boost to the state.

Of course, these transitions are not without anticipated challenges. With the ongoing cost reductions of renewable energy and battery storage, and the ageing state of the vast majority of our generation fleet, the pace of technology change will only continue to accelerate across Australia. It is increasingly apparent that policymakers, regulators and market operators need to take a more strategic approach to prepare for future electricity system needs.

The right solutions would need to coherently meet South Australia's ambitions for a low carbon electricity sector and consumer needs for reliable and low-cost electricity supply. There are a range of solutions available to achieve this including:

- Assessing options to strengthen and increase the interconnection of the NEM, potentially through innovative investment models.
- Leveraging the opportunity and role of battery storage – at residential and business scale as well as distributed at scale throughout the network and in electric vehicles.
- Driving innovation in the way renewable energy generation interacts and supports the electricity network. There are numerous ways in which new renewable energy and storage technologies can provide services that the power system needs.
- Refining the role of key energy market bodies in securing market-balancing infrastructure as a social good.
- Re-purposing retiring fossil fuel generators to provide market-balancing services, while avoiding their ongoing consumption of fossil fuels.

Unlocking these solutions requires a carefully planned energy system, with market design and rules that can allow ongoing innovation and commercial investment in the most appropriate longterm solutions for South Australian electricity customers. This can ensure that South Australia continues to leverage its competitive advantage in renewable energy.

The most effective package of solutions for the energy market will take time to develop. However, with engineering and technical capability, and sophisticated energy market institutions and operators, there are many options available to support a transitioning electricity sector.

There has been a lot of recent misunderstanding and disingenuous reporting of recent events in South Australia and the CEC is playing an active role in briefing stakeholders and media on the reality and outlook for the state's energy system. We look forward to working with all stakeholders on constructive energy market reforms that can facilitate the transition of Australia's energy system to one that is smarter, cleaner and safer.