# SOUTH AUSTRALIA

## Pioneering Australia's Energy Transformation

Australian Energy Council

November 2016

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# EXECUTIVE SUMMARY

The operation of a relatively isolated, high intermittent generation grid in South Australia is revealing new challenges about how we will need to manage these systems in the future. To date seven impacts or risks have been identified from this evolving system:

- Increased spot price volatility
- Increased contract price for baseload generation
- Accelerated retirement of firm generators leading to peak capacity concerns
- Tight domestic gas markets aggravate already marginal operating conditions for firm gas generators in high intermittent operational conditions
- Increased power quality risks during periods of low demand
- Possibility that minimum demand could be met entirely by unscheduled intermittent generation (e.g. rooftop solar PV generation) by as early as 2023
- Reduced system responsiveness to sudden losses of generation.

The energy industry has been investigating some of the potential ramifications and challenges of these new operating conditions. To date three reports have been commissioned from independent expert analysts that look at different aspects of electricity supply in South Australia.

**In December 2015 Deloitte** reported to the Energy Supply Association of Australia on **the consequences of deteriorating returns for conventional generation in increased intermittent generation systems**. Deloitte warned that South Australia may have insufficient capacity to meet peak demand events, although this was prior to the reversal of planned mothballing of gas fired capacity. It also observed that market conditions in South Australia did not support investment in new flexible gas fired generation.

**In September 2016 ACIL Allen** was commissioned by the Australian Energy Council to explore a range of **possible solutions to improve power quality in South Australia.** They found that some proposed interconnector options could be effective in addressing a range of technical issues, but they are either very expensive or have long lead times, or both. A combination of lower cost options to procure incremental inertia, frequency and voltage control and additional dispatchable capacity could collectively provide a quicker outcome. The challenge would be to do so without undermining overall investment signals.

**In July 2016 EnergyQuest** examined **the impact of natural gas supply on South Australian electricity generators**, given the importance of gas as a fuel for reliable electricity supply in South Australia. They found that the South Australian gas market could be short by 2019, as the result of a growing domestic supply gap in the southern states over the next decade. This does not necessarily preclude gas being available to back-up intermittent renewables but it would imply high gas prices and difficulty in contracting more generally.

**Further matters for investigation**

Matters for investigation include:

- Improved design of renewable support schemes that account for their impact on the system;
- More tools for the market operator (AEMO) to procure contingent support in advance of threats to power system security
- Whether market structures need redesign to provide long-term signals for the right mix of services
- How to elicit greater demand flexibility.

Ultimately, these potential enhancements to the energy market and regulatory settings will still need to be underpinned by an enduring (ie, bipartisan), stable and integrated climate and energy policy framework.

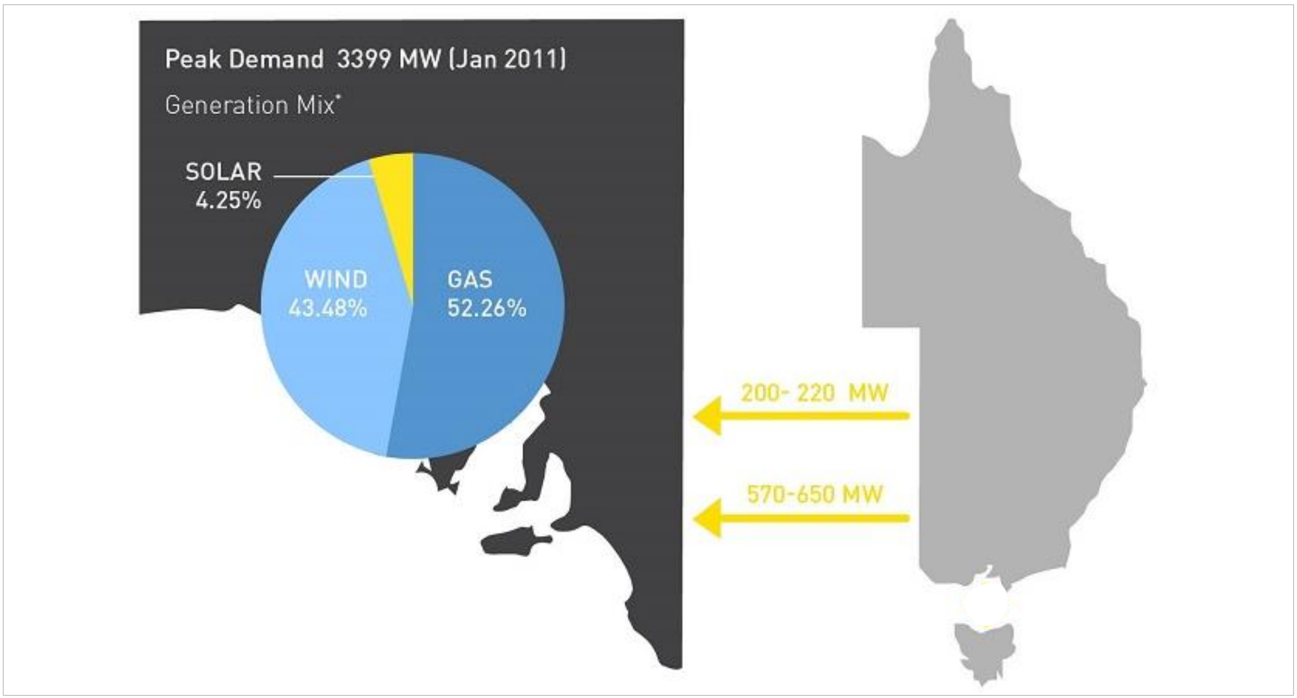
# INTRODUCTION

At the COP21 meeting in Paris in 2015 Australia committed to reduce its greenhouse gas emissions by 26-28 per cent on 2005 levels by 2030, with further commitments likely. Reducing emissions to the levels required this century to avoid the risk of dangerous climate change will require significant decarbonisation across the economy: in particular in stationary energy, transport and agriculture.

By international standards, Australia has had a relatively high emissions intensity electricity supply as the system was built around utilising abundant coal reserves proximate to most mainland Australian cities. Based on current technologies a decarbonised electricity system is likely to utilise a blend of gas and renewables, augmented by increased demand flexibility to adapt better to the varying supply of renewable technologies.

The policy suite to deliver this transformation has, to date, been partial. Over the past decade a national carbon price has been debated, deferred, legislated and repealed. A national renewable energy target was introduced in 2001, expanded in 2009 and amended in 2010. This has been augmented by a range of state based schemes, incentives and targets for renewable energy. The RET uses a certificate based scheme to deliver the lowest cost renewable generation to deliver the target.

**Figure 1: South Australian Generation mix post coal (*from May to August 2016)**




Source: NEM Review, AEMO.

The net result of this policy mix has been that around 50 per cent of Australia's large scale renewable generation has been located in South Australia. Coupled with generous solar feed in tariffs in that state, South Australia now has more than 40 per cent of its generation coming from intermittent renewable sources. The subsequent closure of the last remaining coal fired generator in May 2016 means South Australia is now operating a gas and high intermittent renewable grid.

The operation of a relatively isolated, high intermittent generation grid in South Australia is revealing new challenges about how we will need to manage these systems in the future.

To date seven impacts or risks have been identified from this evolving system:

- Increased spot price volatility
- Increased contract price for baseload generation
- Accelerated retirement of firm generators leading to peak capacity concerns
- Tight domestic gas markets aggravate already marginal operating conditions for firm gas generators in high intermittent operational conditions
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- Reduced system responsiveness to sudden losses of generation.

Since the announcement by Alinta Energy to close the Northern Power station in 2015, the energy industry (the Energy Supply Association of Australia until December 2015 and the Australian Energy Council since January 2016) has been investigating some of the potential ramifications and challenges of these new operating conditions. To date three reports have been commissioned from independent expert analysts that look at different aspects of electricity supply in South Australia.

**In December 2015 Deloitte** reported to the Energy Supply Association of Australia on **the consequences of deteriorating returns for conventional generation in increased intermittent generation systems**.

**In September 2016 ACIL Allen** was commissioned by the Australian Energy Council to explore a range of **possible solutions to improve power quality in South Australia.**

**In July 2016 EnergyQuest** examined the **impact of natural gas supply on South Australian electricity generators**, given the importance of gas as a fuel for reliable electricity supply in South Australia.

All three reports were commissioned before the high price event in South Australia in July 2016 and the System Black event in September 2016. Given the reports are detailed and at times highly technical, this overview document seeks to draw them all together in a high level summary of the results of the analysis.

# IMPACTS OF HIGH RENEWABLE INTEGRATION

### 1. Increased spot price volatility

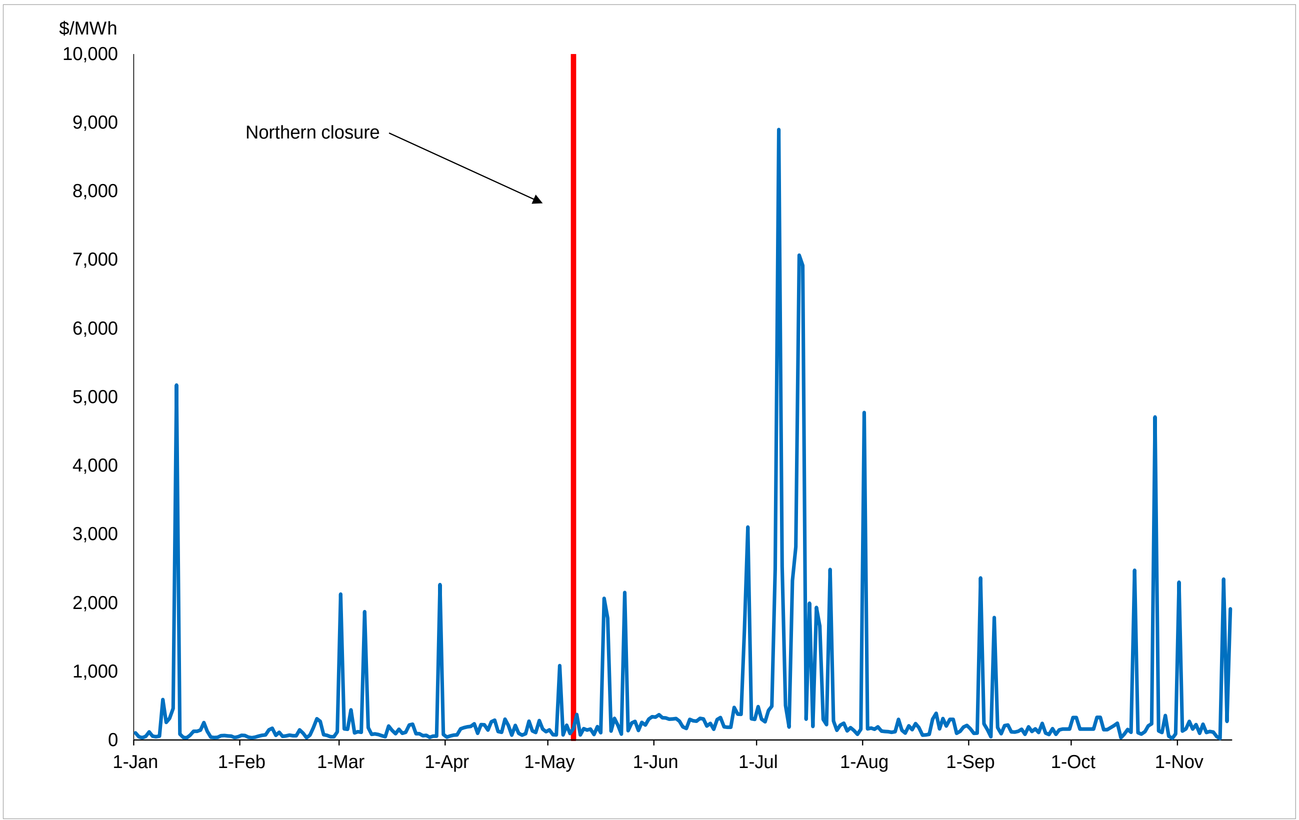
The National Electricity Market is an energy-only market, which uses variations in wholesale prices to signal the entry and exit of generators into the market. This design was based on an electricity grid connected to a range of dispatchable generators with different cost structures. Variations in spot prices encouraged generators to switch on and off in response to changes in demand.

As a result, a level of price volatility is normal in an energy only market, in particular at times of rapid changes in demand. In South Australia we have seen further increases in wholesale spot price volatility, in particular since the closure of the brown-coal Northern Power Station in May 2016.

The solar feed-in-scheme of 16 cents per kilowatt-hour (c/kWh) ceased in South Australia on 30 September 2016. Any new applicant seeking permission to connect their solar system to the grid may only be eligible for a minimum payment from their electricity retailer for any access electricity they export to the grid. The minimum retailer payment in 2016 is 6.8 c/kWh. However, the price paid to customers will increase depending on retail offers.

Since May 2016 the South Australian grid has run on more than 40 per cent of wind energy and more than 4 per cent of solar PV. These technologies do not respond to wholesale spot price signals, but dispatch when the wind blows and the sun shines. As a result they have the effect of suppressing wholesale spot prices when they are operating at scale. When they are not operating a reduced number and scale of generators are required to meet demand. The reduction in supply whilst maintaining demand has the effect of increasing prices. At times of very high demand and little or no intermittent generation (like that which occurred in early July 2016) spot prices can increase significantly in order to get sufficient generation available.

**Figure 2: South Australian wholesale spot market, April to September 2016**




Source: NEM Review

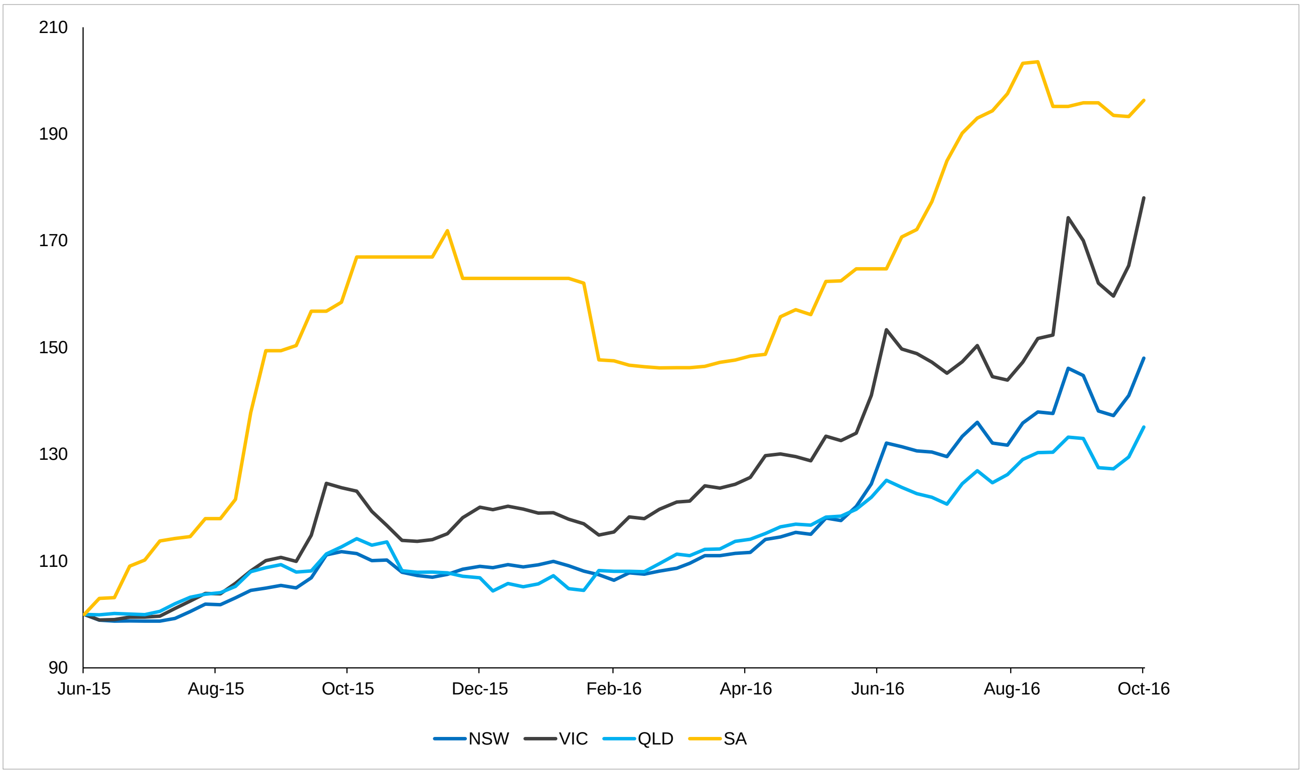
This increased volatility manifest itself in July 2016 when a number of large industrial customers in South Australia were exposed to high spot wholesale prices, resulting from a cold, still period of increased demand but low to near zero generation from wind generators. This resulted in media reporting describing it as a South Australian energy “crisis”. Whilst it would have been possible for these customers to have reduced their exposure to these price events by hedging their electricity contracts, the magnitude of the volatility suggests many customers were surprised by the range of the price volatility in the post-coal market.

## 2. Increased contract price for baseload generation

While the wholesale spot price is the notional price paid for electricity, its inherent and natural volatility means that big consumers and generators often seek to negotiate forward contracts as a natural hedge against this volatility. Around 80 per cent of electricity consumed is contracted in this way. This requires the seller of electricity to be able to guarantee supply in the future, which in turn means in practice that only firm generators can contract into the future (as intermittent generators cannot guarantee supply at any given time).

The announcement of the closure of Northern power station and its subsequent closure resulted in a significant increase in the contract price for electricity in South Australia, especially compared to other NEM states. Figure 3 shows an indexed comparison of contract prices in the four mainland NEM states. In other words, the cost of wholesale electricity in South Australia has relatively increased as a result of continued increases in intermittent generation.

**Figure 3: Future baseload wholesale prices CY 2017 indexed**




Source: NEM Futures

### 3. Accelerated retirement of firm generators leading to peak capacity concerns

In its report in December 2015, Deloitte observed the deteriorating operating conditions for firm generators in South Australia as a result of high levels of intermittent generation. Typically, wind generation is dispatched ahead of all other generators to meet demand, in part because wind's marginal cost of production is virtually zero (similarly with solar PV). As a result, as wind and solar have increased, they have displaced conventional generators. This has reduced greenhouse emissions, and accelerated the closure of older, high emissions generators like Northern and Playford Power Stations.

As Deloitte observed in their 2015 report:

*The initial growth in renewable generation appeared beneficial for consumers in South Australia. It reduced greenhouse emissions and suppressed wholesale electricity prices as a result of the excess supply created. Reliability and power quality were not compromised because the dispatchable fossil fuel plant was still available to provide energy and grid stability when required. But some of this thermal plant located in South Australia has subsequently become uneconomic as the cost of repair and refurbishment exceeds the reduced margins from weaker wholesale electricity prices.*

These deteriorating operating conditions were reflected in the mothballing of 249MW of gas combined cycle capacity at Pelican Point and the planned closure of Torrens Island A gas power station (480MW) by 2017. Both these decisions have now been reversed, although the capacity at Pelican Point was only brought back on after the price spikes in July at the request of the South Australian Government. These conditions have made South Australia increasingly reliant on supply from Victorian brown coal generators via the Heywood and Murraylink interconnectors.

Deloitte warned that South Australia may have insufficient capacity to meet peak demand events, although this was prior to the reversal of planned mothballing of gas fired capacity. It also observed that market conditions in South Australia did not support investment in new flexible gas fired generation.

4. **Tight domestic gas markets are aggravating already marginal operating conditions for large scale firm generators in high intermittent operational conditions**

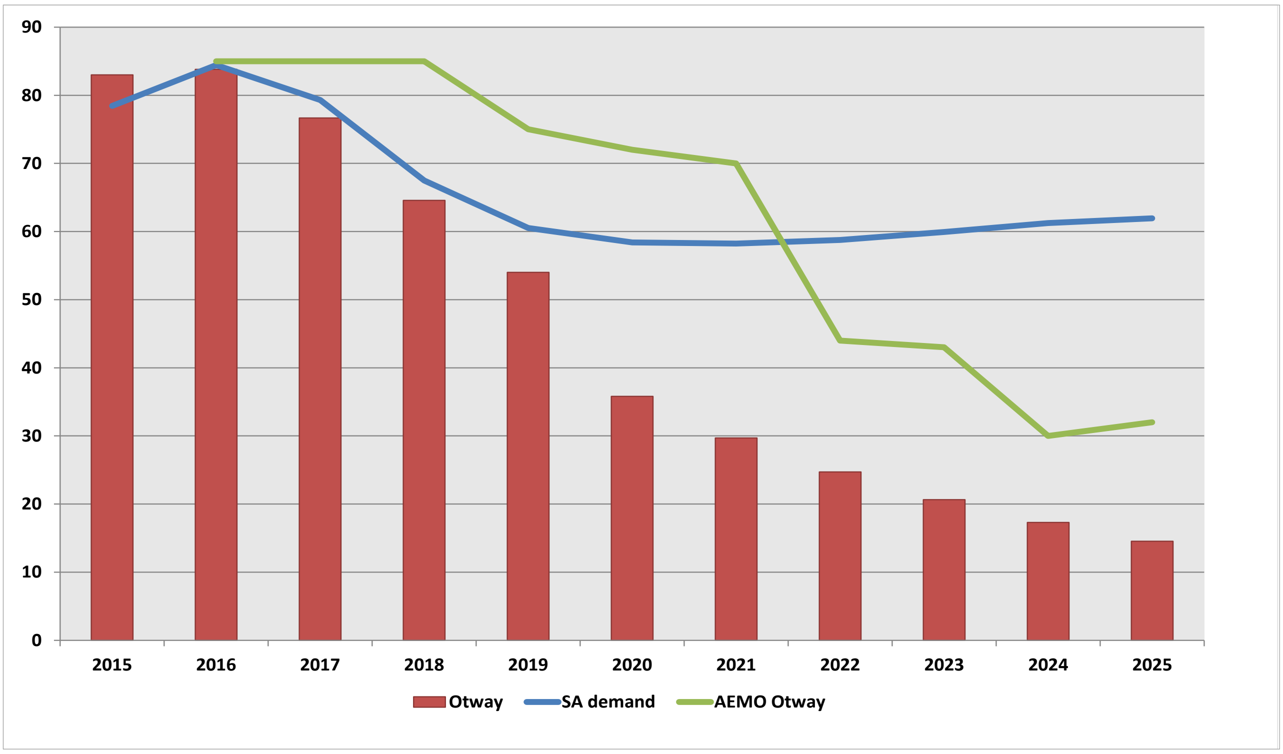
In the absence of large scale zero emissions generation (hydro, nuclear), delivering large scale electricity supply while meeting reducing emissions targets is currently likely to require a combination of gas and renewables generation. As renewables capacity increases, large scale thermal generators shift from being primary to supporting generators, switching in and out of service depending on the intermittent supply coming from renewable generators.

This model has a number of commercial and technical challenges. In particular, the ability of gas generators to perform this supporting role at the lowest cost to consumers depends on the availability of gas supplies to those generators. What has emerged in South Australia is that illiquid gas markets in south-eastern Australia are exacerbating already challenging operating conditions for large scale gas generators operating in the state.

In June 2016 the Australian Energy Council commissioned EnergyQuest to report on the emerging east coast gas market conditions and their impacts on the South Australian electricity market. In its report (attached, published in July) EnergyQuest gas expects the east coast domestic gas market will remain tight over the 2016-25 timeframe.

EnergyQuest finds that the South Australian gas market could be short by 2019, as the result of a growing domestic supply gap in the southern states over the next decade. It is plausible that, without material supply of northern gas, South Australian baseload gas demand exceeds Otway Basin supply from 2020, even in a best assumed case whereby all Otway gas supplies South Australia. As the report states: “This does not necessarily preclude gas being available to back-up intermittent renewables but it would imply high gas prices and difficulty in contracting more generally”.

**Figure 4: South Australian gas supply and demand PJ/annum**




Source: AEMO, EnergyQuest: 2015 numbers are actuals

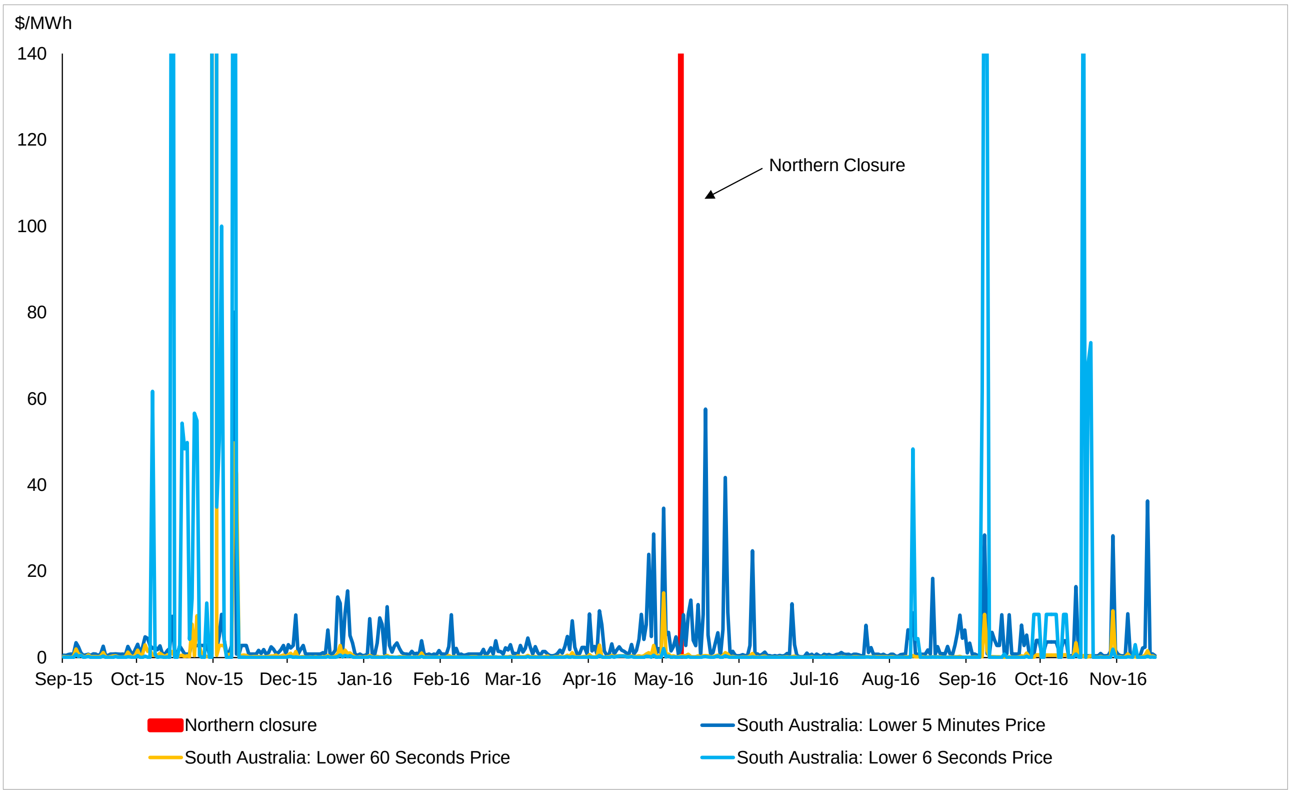
From the experience of South Australian gas generators, it is increasingly difficult to contract gas to meet future demand as intermittent generation increases, as the volumes of gas required are dependent on knowing how much intermittent generation will be available in the future. Gas generators are at increasing risk of over-contracting gas (which they still have to pay for under take or pay conditions) or under contracting, meaning they have to undersupply or buy gas on the spot market and try to recover these costs in the wholesale market. In short, illiquid gas markets magnify the cost of supplying firm generation in a high intermittent generation market.

### 5. Increased power quality risks during periods of low demand

A key issue emerging from observing the South Australian grid under high renewable integration is the challenge of managing power quality (frequency and voltage). This is because most intermittent generators are asynchronous, meaning they adapt to, rather than adjust, the levels of frequency and voltage in the grid at the time. Managing frequency in particular has been relatively simple using conventional thermal generators, as most of these can be relatively easily configured to provide frequency regulation services (FCAS). Provision of these services is through an FCAS market in the NEM, but traditionally the value of this market, and of FCAS services, has been very low, reflecting the low marginal cost of providing the service.

However, this value is changing in South Australia with the reduced number of FCAS service providers in the market and the reduced numbers of them operating at any given time. The FCAS market in South Australia has become more volatile since the closure of the Northern Power Station in May 2016, as well as the effect of the upgrades on the Heywood Interconnector around the same time.

**Figure 5: South Australian FCAS market prices August 2015-16**




Source: NEM Review, AEMO

The risk of a major supplier of FCAS (which can be provided by some interconnectors) being constrained resulted in AEMO contracting additional FCAS services in South Australia. This followed a blackout on 1 November 2015 in South Australia following the sudden loss of the Heywood Interconnector on a Sunday night during a period of relatively low demand. South Australian firm generators had to take over managing frequency whilst also trying to replace the supply shortage.

In its review of the potential increased risks to the reliability of the South Australian system (report attached), ACIL Allen observed that the state had become increasingly dependent on its interconnection to Victoria. "While the threat of separation is very low, the consequences can be very high," the report concluded[1].

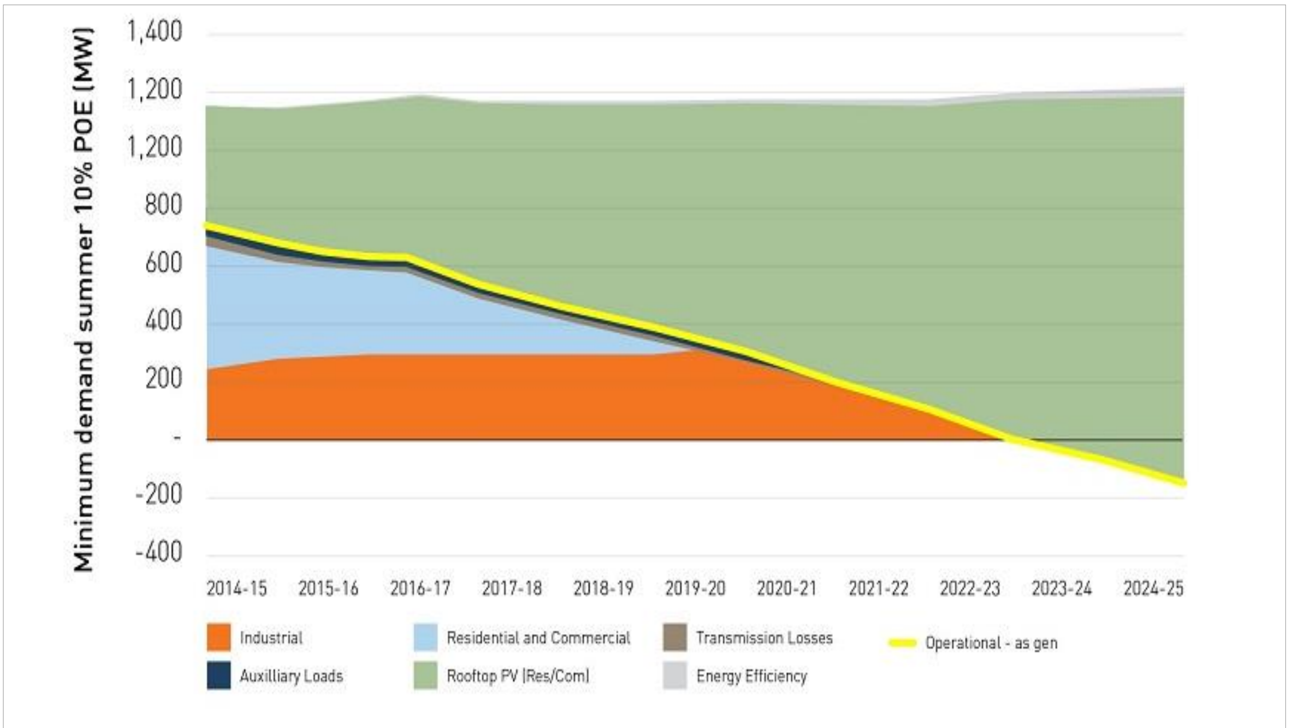
ACIL Allen observed that the low probability events that might separate South Australia from the rest of the NEM mostly fell outside normal planning and operating obligations of AEMO, and would typically require some sort of investment or change to market arrangements[2]. Comparing a range of possible solutions, ACIL Allen concluded each posed different costs and addressed different aspects of the state's reliability challenges, but that there was no single technical solution which emerged as the obvious solution[3].

**6. Possibility that minimum demand could be met entirely by unscheduled intermittent generation (eg, rooftop solar PV generation) by as early as 2023**

In 2015 AEMO forecast minimum demand in South Australia as part of its annual demand forecasting[4]. It was the first time AEMO had looked at minimum demand, in response to the continued uptake of rooftop solar PV in Australia. South Australia has around 26 per cent of dwellings now fitted with rooftop solar PV, which is the highest penetration rate of rooftop PV in the world.

In its forecast AEMO observed that if deploy rates continued in South Australia, then by as early as 2023 minimum demand (which was now forecast to occur at around lunchtime on Boxing Day) would be met entirely by the unscheduled generation from all rooftop PV systems in that state[5].

**Figure 6: Minimum demand in South Australia, 10 per cent POE 2015-25**




Source: AEMO

[1] ACIL Allen Technical Challenge Integration of Renewables, Executive Summary
[2] ibid
[3] ibid
[4] AEMO National Electricity Forecasting Report, June 2016
[5] AEMO National Electricity Forecasting Report, June 2016

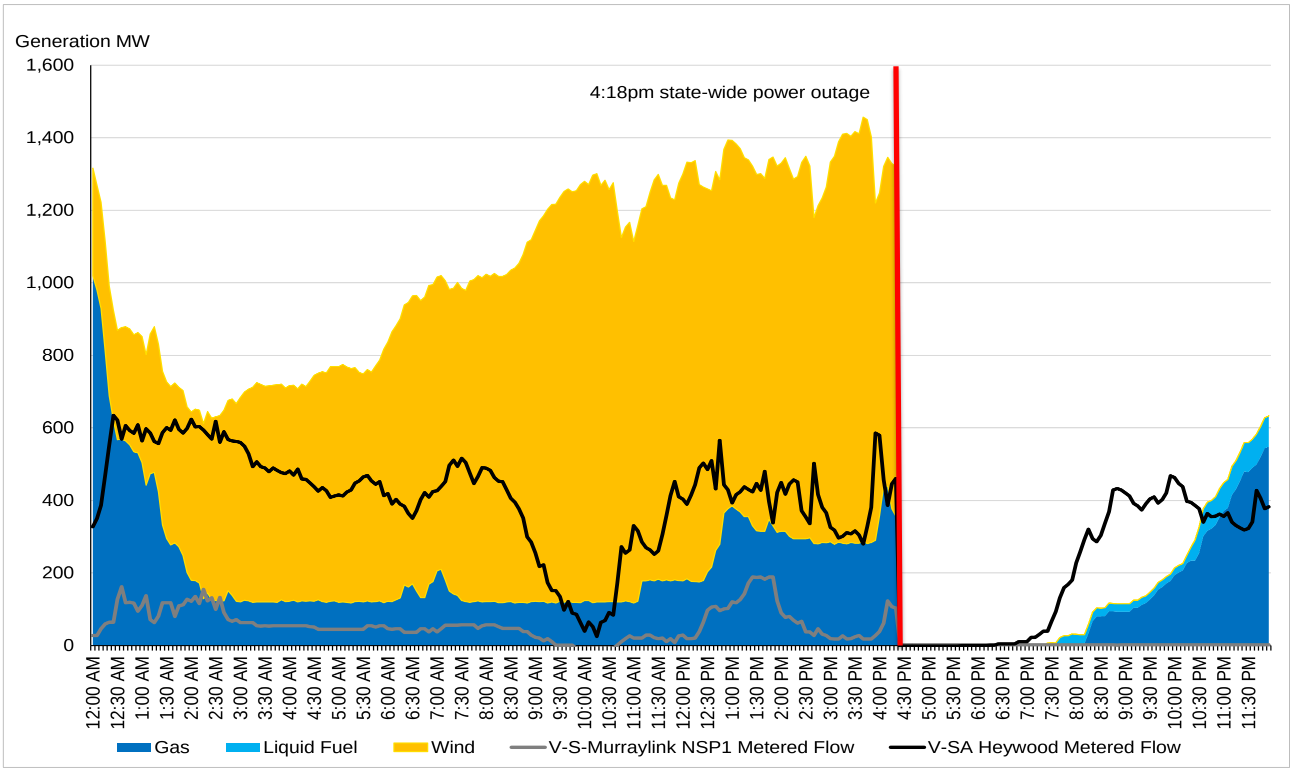
This is significant for a number of reasons: rooftop solar PV systems cannot be controlled by the market operator, so they will generate depending on the weather conditions at the time. They do not provide power quality services, indeed solar PV systems can be very volatile under intermittent cloud conditions, meaning power quality would need to be potentially provided as a pure service, not in addition to the provision of generation. It is unclear how available power would be distributed across the grid, given the high penetration of rooftop PV in some post codes and lower penetration in others.

The value of this observation by AEMO was to remind us to consider the range of technical challenges of shifting to a high intermittent generation grid, where possible ahead of those challenges manifesting themselves into reliability issues.

### 7. Reduced system responsiveness to sudden losses of generation

On 28 September during a major storm the South Australian grid blacked out completely (system black). At the time of writing, AEMO has produced two reports on the event. The event was triggered by damage to transmission lines in the north of the state, caused by lightning and strong winds. This resulted in a rapid change of voltage which resulted in eight wind farms located in the mid-north of the state switching off. The loss of around 445MW of generation could not be covered by the single thermal generator operating at the time or the remaining wind farms in the state's south east. As a result, the Heywood Interconnector, which was operating at close to its rated capacity at the time, tried to respond and cover the shortage, forcing the market operator to turn it off and resulting in a system black.

**Figure 7: Generation timeline, South Australia, September 28-29 2016**




Source: NEM Sight

Detailed investigation into the series of events and possible remedial measures is continuing, including the ability of the wind farms (or indeed any thermal generator) to ride through the changed voltage conditions triggered by storm damage.

More significantly, the event highlights the different operating nature of intermittent renewables at scale, and how these grids will need to be managed in higher risk situations (like major storms) in the future. In particular, a grid utilising a high proportion of intermittent generation is less capable of responding to sudden losses of generation, because the intermittent generation cannot increase output. The higher the proportion of this type of generation, the greater the response would need to be from remaining firm generators.

While the events that caused the cascading series of events in South Australia that led to the system black event are still being investigated, a key learning will be how to operate and configure high renewable grids under these circumstances to minimise the scale of the outage.

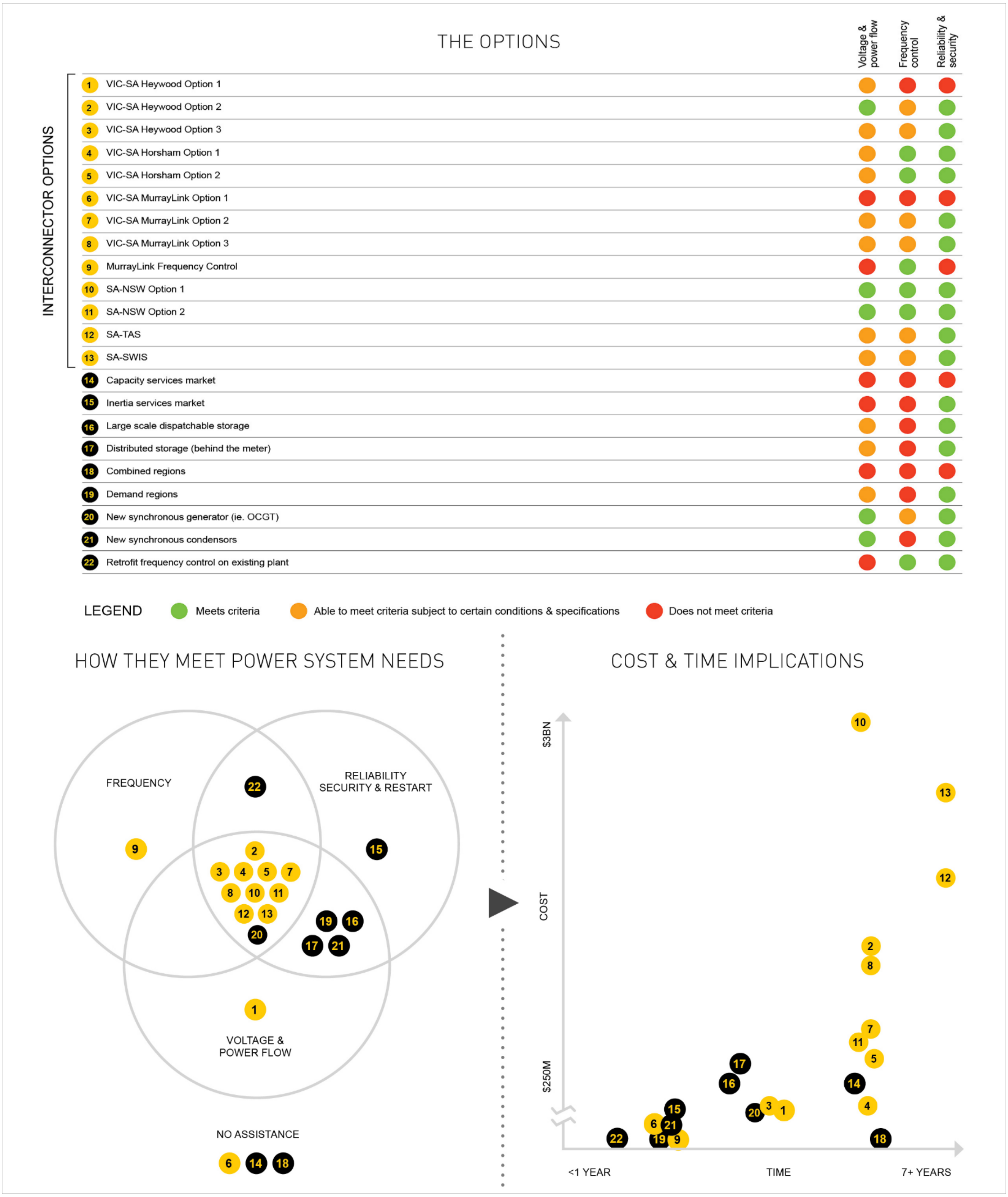
# POTENTIAL SOLUTIONS TO THE TECHNICAL CHALLENGES

South Australia is pioneering the integration of high levels of intermittent generation in a constrained grid. It is an important test case, albeit accidental, in understanding how electricity grids will need to work in the future to manage the high penetration levels of these new technologies.

One challenge is that this is an active learning process. In the time since the energy industry has been exploring the impacts of high renewables penetration, there have been three major reliability and price events within a year. Each event has added new challenges and provided new information to be considered. It is reasonable to assume this active state of learning will continue.

In its 2016 report for the Australian Energy Council, ACIL Allen developed a matrix of 22 possible solutions to a range of technical challenges – voltage and frequency control, system reliability and system restart - to assess them for their functionality, cost and other implementation challenges. A summary of this cataloguing of solutions, how they meet power system needs, their costs and time implications is provided in Figure 8 on the next page.

**Figure 8: Solutions to high renewable integration in South Australia, ACIL Allen 2016**



While the report was not able to identify a single “silver bullet”, the following conclusions can be drawn:

A combination of options, including: installation of frequency control on Murraylink and plant located within the region, the procurement of additional inertia, demand response, a new synchronous generator and/or a synchronous condenser[6] could collectively provide a relatively low cost, short lead time and low risk complementary package of solutions.

Some of the proposed interconnector options, including SA-NSW and further upgrade of the VIC-SA links[7] could be effective in addressing a range of technical issues, but they are either very expensive or have long lead times, or both.

Due to time and the need to limit the scope of this work, ACIL Allen did not address other relevant considerations such as: whether sufficient peak capacity can be maintained in South Australia under current market structures and polices, nor what the risk is of large regulated investments such as interconnectors becoming effectively stranded before customers have finished paying for them. The analysis was carried out before the system black on 28 September, so it does not account for any implications of that event.

# FURTHER POLICY CONSIDERATIONS

**Renewable energy policy reform**

The current design of renewable schemes such as the Renewable Energy Target and the ACT’s contracts for difference are focussed on the delivery of the *scheme* at the lowest possible cost to consumers. This is different from delivering the lowest cost *system* within the envelope of the required reliability and the desired levels of renewable penetration. Accordingly, these schemes do not consider the grid stability consequences of high concentrations of intermittent generation, of the potential and future value of dispatchable renewable generation, nor attach any specific value to developing renewables that can provide ancillary services.

The high renewable generation conditions in South Australia are in no small part a result of these design features of the RET. Planning controls for new renewable projects are currently only limited to grid access issues and avoiding transmission constraints. Despite the events of the past year, three more wind farms were commenced in South Australia.

To the extent that renewables policy is seen as an essential part of future energy policy design, it may be prudent to review its design to reflect the broader range of values and considerations emerging from the South Australian experiment.

**Reviewing market rules and structures**

With the benefit of hindsight, the simplest way to minimise the impact of the 28 September blackout may have been to reconfigure the operation of the grid at that time. The normal operation of the National Electricity Market (NEM) is to provide adequate supply of electricity at the lowest possible cost. To deviate from this, AEMO would have needed to direct generators and transmission line operators to change how they were operating to enable the grid to be better configured to respond to a sudden loss of generation. This would mean a higher cost of operation for the duration of these conditions. AEMO would have to make this decision before it was clear whether it was necessary or not.

[6] Options 9, 15, 19, 20, 21 and 22 respectively
[7] Options 2, 4, 5, 10 and 11

Going forward, the question is how the market rules could be reconfigured to discover the most efficient way to solve simultaneously for both lowest cost and increased reliability under these new conditions. Options already canvassed include:

- The creation of an inertia market. Inertia is a function of the physical nature of most generation assets, including hydro. Systems with high inertia are generally able to ride through disturbances like a transmission outage or other generators in the system tripping. Intermittent, asynchronous generation does not provide inertia.
- Raising the market price cap from its current $14,000 MWh may help ensure that scarcity of supply is sufficiently valued to ensure supply is available when intermittent generation is unavailable[8].
- Capacity payments, which would work most effectively under a market mechanism. These could provide more predictable short-term prices, with less volatility, as the trade-off is usually to have a much lower energy price cap, but may not be lower cost overall. In the NEM, the contracts market functions as a quasi-capacity remuneration mechanism, so the question is whether a formal mechanism could overcome issues such as low liquidity, which has been a concern in South Australia for some years. Notably the influx of wind generation has done nothing to alleviate this concern.

**Demand flexibility – the role of consumers**

Consumers have a growing role in the delivery of energy generation and services through their investment in distributed energy resources (DER) like solar PV, storage, but also older DER such as hot water load. While this has had both a positive and negative impact on the stability and security of the electricity system, there will be increased value in greater demand flexibility to take advantage of periods of abundant supply (windy, sunny) to help reduce demand during periods of reduced supply.

This load shifting needs to be schedulable (firm) if it is to have real value in the modern electricity grid, which will require a combination of incentives and technology. While increased demand flexibility would have been unlikely to avert the system black in September in South Australia, it would help ameliorate the higher operating costs associated with an increased intermittent generation system.

**National energy and climate policy**

South Australia’s status as the world’s leading intermittent integration grid is a function of the design of national renewable energy policy. While the state’s technical challenges are relatively unique, its situation is largely the product of national climate and energy policy.

It is not possible to properly address the situation in South Australia without first addressing the need for co-ordinated national climate and energy policy in Australia. Self-evidently, achieving national emissions reductions of 26-28 per cent by 2030 requires national policy to deliver it. In turn, these targets are only a staging post to deeper emissions reductions required beyond this date. Whatever the instruments chosen to drive abatement, they need to provide clear signals to the market of both what to build and what to close (and when). With clear rules the market can balance the energy trilemma of cost, reliability and emissions reduction more effectively than government prescription. This is not possible until there is bi-partisan, national and enduring policy designed to deliver the decarbonisation of Australia’s electricity system.

[8] Riesz, J., Gilmore, J. and MacGill, I., 2016, Assessing the viability of Energy-Only Markets with 100% Renewables, Economics of Energy & Environmental Policy, 5(1)