# NEM RISK BULLETIN

# THE 18 DAYS OF SUMMER – DISPATCHES FROM THE WORLD'S BIGGEST RENEWABLE EXPERIMENT

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**Contents**



## The 18 days of summer – dispatches from the world's biggest renewable experiment

South Australia being effectively isolated from the rest of the National Electricity Market in the middle of summer was a major black swan event for the world's biggest electricity experiment.

When six transmission lines came down on January 31 as a result of wild weather in Western Victoria, the Heywood Interconnector – the main link between South Australia and the outside world – was knocked out.

That left a state of 1.5 million people isolated, and having to try and keep the lights on with around 50 per cent of electricity supplied from intermittent renewable generation during what is historically the most testing time of the year for Australian electricity grids.

South Australia narrowly dodged some big bullets. The loss of the transmission line nearly triggered a second system black, and the SA grid operated on a wild roller coaster ride until the connection to Victoria was reinstated on February 17.



These 18 days in February were also a critical and valuable live trial of how the future might be for the whole of the NEM. If the idea is to move to large scale renewables firmed by gas and batteries, then the latest South Australian lab experiment was an invaluable insight into the challenges that lie therein.

**The event**

Six transmission towers were knocked out on by strong winds on the afternoon of January 31 2020. At the time the weather was hot, humid and still in Victoria and electricity demand was near record highs. A cooling front had moved through South Australia, meaning the state's fleet of wind farms were powered up and exporting into Victoria to help meet supply.

The sudden loss of around 500MW of electricity supply in Victoria was offset by Alcoa's aluminium smelter at Portland being tripped off by the event. The Mortlake gas generator was also isolated. There was enough generation and voluntary load shedding on the Victorian side of the storm to narrowly hang on without any blackouts. But it was tight.

On the South Australian side things were much more serious. The 500MW of electricity that was being exported to Victoria bounced back onto the much smaller South Australian grid, driving the frequency levels there right to the edge (51 hertz) of where the system would shut down because of the sudden, and potentially dangerous, surge in power. It was a massive drop infrequency that caused the system black event in 2016.

Fortunately South Australia hung on. It was helped by many rooftop solar systems in South Australia tripping off in reaction to the surge in frequency. But having survived the breakup, the isolated Croweater grid was now faced with the prospect of being effectively islanded until the transmission towers could be repaired. In the middle of summer. The much smaller Murraylink transmission line was still operational, but at 220MW it would only provide limited help. As far as the Australian Energy Market Operator (AEMO) was concerned, South Australia was on its own until further notice.

**The weather**

South Australians got a big break with the weather. February in Adelaide is normally hot and dry. Heatwaves are common, electricity demand reaching in excess of 3,100MW at the extremes. The weather for the start of February was unusually mild. Temperatures only went above 30 degrees over the weekend of February 8-9. There were no heatwaves.

During most summers over the past decade South Australia relied on the Heywood interconnector, the Northern coal fired power station, or both, to keep the lights on. Now it had neither.

On the positive side, AGL had recently commissioned its 210MW fast start Barkers Inlet power station, and the Weatherill government had installed 250MW of emergency generation back in 2017. The ageing Torrens Island A power station was still on line. The state had around 2,600MW of gas generation, 660MW of diesel and more than 3,500MW of wind and solar PV, both utility and household scale. It also had another 130MW of large scale battery storage for a hour. Batteries were not the state's lifesaver as painted by some activist bloggers, but useful at the margins.

**The market**

As a result of mild weather, subdued demand and sufficient generation, the SA grid operated with increased price volatility but otherwise without incident over the 18 days. There was sufficient flexibility in  the gas generators to work in concert with the wind and solar PV. Wholesale spot prices tracked above the long run average for the second week in February, but given the circumstances it was remarkably unremarkable. As an odd side event of the islanding, both Mortlake (gas generator) and Portland (aluminium smelter) were brought back on line, but operationally in the South Autralian side of the grid.

**The frequency**

The most significant impact of the island was not in the supply of energy, but the supply of power quality services. The loss of the Heywood transmission line removed a source of Frequency Control Ancillary Services (FCAS). This is one of the more obscure activities in an electricity system, where generators and batteries contract to manage the job of stabilising the frequency of the system at 50 hertz.

Keeping this background humming "note" stable is absolutely critical to the operation of the grid. In Queensland where the grid is still largely supplied by a rugby scrum of large, coal fired power stations, FCAS is not an issue, and costs almost nothing. Large power stations can easily lock on to the frequency note created by the spinning of their alternators and modify their spin rate to keep frequency nicely at 50 hertz (about 3000RPM).

But in a high renewables grid like South Australia, providing FCAS becomes scarce, and expensive. As a basic rule renewable generators do not provide frequency services (some wind turbines can if they are specifically modified for the purpose, but it's expensive). FCAS is largely provided by gas turbines and by the large scale batteries, with a very modest amount of demand response also in the market. According to AEMO, providing FCAS is the main source of income for the large scale batteries installed in the NEM.

The biggest problem during the SA island experiment wasn't energy. It was FCAS. FCAS costs were estimated to be $93 million for the 18 days. The South Australian market is only worth around $1 billion a year, so the value of the electricity for the 18 days was only around $49 million. That's a big problem.

The price paid for FCAS services to gas generators and batteries is a lot more than what it cost to provide the service. South Australia's batteries have been creaming huge profits from FCAS every time the state is islanded or at risk of islanding. They are estimated to have earnt $40 million over the 18 days. This suggests in times of FCAS scarcity, the sellers of the service are able to strategically bid in the market to inflate the price.

**The lessons**

The recent islanding of South Australia provides valuable lessons about the future design and operation of high renewables grids. It confirms the operability of gas and renewables grids, although there are indicators of this system operating at a higher average price without supply of cheaper coal generation from Victoria.

Any grid planning needs to consider the increased frequency of transmission faults from weather events, suggesting there is a risk of over reliance on transmission assets given increased frequency of weather events which can disrupt their operation.

Most importantly, a high renewables system needs to ensure it can source sufficient FCAS providers to ensure power quality is maintained at a reasonable price. Presumably in the move to a renewable future there will be more large scale batteries and therefore more competition.

Thanks to Paul McArdle, Allan O’Neil and Jonathon Dyson for their diligent scrutiny of these events over the past weeks!

You can find a Briefing Paper on power quality here.

**Gas futures - sunrise and sunset**

Two reports this week displayed the yin and yang of Australia's gas future. Tasmania's hydrogen strategy set out the Apple Isle's plans to capture a large chunk of potential future export markets of "green" hydrogen, as well as supply local uses as diverse as agriculture, transport and Australia's Antarctic research division. Over on the mainland, Evo Energy's draft business plan for its ACT gas distribution network for 2021-26 gives some early indicators of the challenges that may be faced if our existing natural gas infrastructure becomes stranded. The link between the two is the possibility of converting that infrastructure to run on hydrogen instead. The two reports and how they compare to what is going on elsewhere in the country are explored below.

**Sunrise - Tasmania's renewable hydrogen strategy**

The strategy was launched by the Premier with a claim that green hydrogen – hydrogen produced by electrolysis powered by renewable energy sources – was "one of the most extraordinary sunrise opportunities that Tasmania could ever step into". He also noted that it included "Australia's largest hydrogen industry support package". These include a $20 million Tasmanian Renewable Hydrogen Fund and $20 million in concessional loans. Additional measures include up to $10 million worth of support services including competitive electricity supply arrangements and payroll tax relief. Details are scant, but the Tasmanian government will run a competitive "expression of interest" process to select projects. Eligible projects will be in any of the areas of renewable hydrogen production, storage, distribution, export and use within Tasmania, indicating the number of moving parts entailed in building a thriving hydrogen sector. What it lacks in focus, it makes up for with enthusiasm.

A successful hydrogen strategy will need to do more than throw money at the sector until it sticks. Careful co-ordination will be needed, which governments will inevitably (and appropriately) take the lead on. Supply and demand will need to be nurtured at similar rates. Too much supply and the price will collapse - unless the government mediates through a fixed offtake price which could drain the budget, and they'd still have to find somewhere to store it until it can be offloaded. Too much demand and customer confidence could be dented by price spikes or shortages.

There will need to be a constant competitive scan. Most if not all hydrogen uses will be competing with alternate sources of energy or feedstock. In transport, hydrogen will be competing with both EVs and conventional combustion engines. In energy storage, it will be competing against chemical batteries of various types and pumped hydro. In agriculture it will be competing against other ammonia production processes. Green hydrogen's zero emission credentials may not count for much in these markets unless it is regulated in and/or Australia revisits carbon pricing.

Tasmania will also need to keep an eye on what other states and territories (and the commonwealth) are doing in this area. Their reign as providers of the largest hydrogen support package could turn out to be short lived. Victoria has recently consulted on its own hydrogen investment program and is already contributing to the Hydrogen Energy Supply Chain project, a joint Australian – Japanese initiative to prove up the ability to transport hydrogen at scale, a necessary precursor to any export industry. Unlike Tasmania's plans this project uses gasified brown coal as the feedstock so is not zero emissions.

South Australia launched its hydrogen action plan last September and has so far supported four hydrogen development projects with over $40m of grants and loans. West Australia and Queensland also issued hydrogen strategies last year, each with up to $10m available for industry support. The Commonwealth has also set out a national approach, led by Alan Finkel.

Australia's far from the only country seeking to develop a hydrogen industry. At least 19 countries around the world have industry development plans, typically with extensive government support. Only this week, a feasibility study into what could be the world's largest green hydrogen project off the Dutch coast was announced. The NortH2 plan includes 3-4 GW of offshore wind dedicated to hydrogen production in place by 2030, rising to 10 GW by 2040. This would produce 800,000 tons of hydrogen annually.

One of the key initiatives common to most states' hydrogen plans is exploring how to repurpose existing gas transportation infrastructure to carry hydrogen instead of natural gas. In all cases the first step is to trial "blending" of a small proportion of hydrogen (up to 10-15 per cent) in a section of the gas distribution network. This approach allows for testing of leakage rates (hydrogen is a smaller molecule than methane so can escape more easily) in a safe and controlled way and does not require change in consumers' gas appliances. Stepping up to full hydrogen injection is a different order of challenge, both to ensure leakage risks can be managed and to upgrade user appliances, although the feat of switching over gas types has been done once before with the switch from town gas to natural gas.

Blending trials are underway across Australia, with projects in West Australia, NSW, Victoria and South Australia. Tasmania's strategy promises to explore this opportunity with the owners of the network there (which is less extensive than other state, so not quite such a high priority overall). Government support, from either the state government or ARENA is a feature of all these trials, although the private owners of the gas networks are leading the way, spurred by the knowledge that their assets have no future in a zero emission world if they can't move away from transporting fossil fuel gas.

**Sunset – ACT gas**

A notable exception to the support from governments for repurposing the gas networks in this way is the ACT. While the gas network there (which is 50 per cent owned by the ACT government) is testing hydrogen, the ACT's climate change strategy does not seem to envisage a hydrogen future for it. Although the strategy does not completely rule out such a future, it appears much more focussed on an aggressive electrification strategy, suggesting that around 60,000 existing households would be disconnected from the gas network by 2025, rising to 90,000 in 2030 and 100 per cent by 2045. While these numbers may include new builds that are never connected in the first place these represents a rapid defection rate for a gas network with around 160,000 customers currently.

If the ACT government's scenario of rapid disconnections plays out, there are a number of consequences it will have to grapple with. The electricity network will need to deliver the energy currently delivered by gas. Gas has a much bigger seasonal peak use to winter heating needs than electricity. Evo Energy's analysis suggests that the electricity network may have to cope with double its existing peak demand, which will require some serious augmentation expenditure.

There is also the question of what happens to the gas network. Under its draft business plan for 2021-26 (which is subject to regulatory approval) Evo Energy expects to have a capital base worth $370m in 2026, just as the mass exodus of customers is expected to be taking place. It also needs to spend $13m a year in new capital expenditure just to keep the network going. Mass exodus would create a death spiral where it would need to increase its prices on a per customer basis just to remain solvent, which would drive other customers off the network. The last customers are likely to be those least well placed to switch to electric alternatives – low income households and renters. At some point the government may have to step in and pay for these customers' new electric appliances.

Over a quarter of the network's current operating expenditure is actually government fees and taxes. These will have to be recovered from elsewhere – probably through electricity prices. The government will also need to deal with the financial consequences of writing off its own investment in the gas network and may face a claim from its joint venture partner (Jemena) to make good their losses. Finally, there will be some costs involved in safely decommissioning the network. At this point there will eb no customers left to pay for this, and the network business itself will be insolvent, so it is likely to be government that picks up the bill. None of these factors are addressed in the Climate Change Strategy.

Electrification is a risk across all gas networks. Severa studies in recent years have argued that it is cheaper with modern electric heating and hot water options than gas. And the challenges of conversion to hydrogen may prove insurmountable. But it is obvious why gas networks and most governments see the value in exploring whether the networks can be repurposed given the risks and costs that would entail from their demise.