A-Lab Innovation Frame 2: 'The wholesale markets are designed for renewable energy' – Research Context

1.1 Background

Australia's National Electricity Market (NEM) is one of the most complex and sophisticated wholesale electricity markets in the world. In 2016/17 $16.6bn was traded in the NEM[1], facilitated through the spot market, where the output from all generators is aggregated and scheduled at 5-minute intervals to meet demand across five interconnected states that also act as price regions.

In their May 2017 report on the state of the energy market, the Australian Energy Regulator (AER) concluded that the past 12-18 months had been some of the most challenging Australia's energy sector had experienced since the NEM was established in 1998. While investor uncertainty around the viability of new generation investment and recent coal plant closures had impacted electricity supply, gas supply had also been impacted by Queensland's liquefied natural gas (LNG) projects drawing on reserves from southern Australia, and regulatory restrictions on exploration. The result has been significantly higher electricity spot prices. In 2015-16, thirty-minute settlement prices exceeded $200/MWh almost 4000 times – an unprecedented number. Another 2100 instances occurred in the first nine months of 2016-17[2]. This is now impacting customers with major retailers implementing price rises of up to 20% for residential and small business customers from July 1, with commercial and industrial customers reporting even greater increases[3].

Price isn't the only concern.

South Australia's statewide blackout in September 2016 caused by a severe storm, followed by subsequent supply cuts to some customers in South Australia and NSW through the summer of 2016/17 have raised significant concerns about the reliability of supply. These concerns are compounded by uncertainty around system operation and management in a future with increased reliance on variable renewable energy (VRE) generators both in front of, and behind the meter. The impact of weather conditions on these forms of generation can create new risks in times of high demand or when imports across interconnectors are constrained. These technologies also have different technical characteristics to traditional thermal generators and these differences will need to be managed.[4]

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[1] AEMO, National Electricity Market Fact Sheet, 2017

[2] Australian Energy Regulator, State of the Energy Market, May 2017.

[3] Australian Financial Review, March 2017 (http://www.afr.com/business/energy/electricity/electricity-price-shocks-can-be-call-to-action-on-efficiency-20170228-gunf65)

[4] Australian Energy Regulator, State of the Energy Market, May 2017

The inevitable tension when balancing cost and reliability only adds to the challenge that the system now faces as it navigates the transition to a future where plausible forecasts estimate that by 2050, 100% of electricity generated in Australia could be from renewable sources and almost half of this electricity would be generated by customers[5].

The current electricity system, and its markets, were designed based on one-way flows of electricity from large, dispatchable synchronous generation capacity. Recent events have raised the question as to whether the NEM in its current form is delivering for customers. This has prompted a series of reviews looking into reliability, security and price outcomes of the markets with a view to making recommendations for reform. These include:

- The Australian Government's *Independent review into the future security of the National Electricity Market* (the Finkel Review);
- The AEMC's Reliability Frameworks Review;
- AEMO's Future Power System Security (FPSS) Program;
- The AEMC's System Security Market Frameworks Review; and
- The AEMC's Frequency Control Frameworks Review.

1.2 Purpose

The purpose of A-Lab is to stimulate innovation in the Australian electricity sector to support the transition to a future powered by renewable energy. A-Lab's vision for the future is one where **the wholesale markets are designed for renewable energy**, where vibrant markets support customer choice, system reliability and security, low emissions and social equity.

Therefore, the purpose of this context paper is to briefly outline some of the areas for innovation relating to the creation of this future. It will draw heavily on the reviews listed above, particularly the Finkel review and its relevant recommendations, in order to provide some foundational information to support the A-Lab innovation process.

These areas for innovation relate to the key challenges posed by the increase in variable renewable energy (VRE) generation and reduced synchronous generation on the grid, and specifically the functioning of existing energy markets or the potential need for new markets or market mechanisms. They include:

- A changing **wholesale energy market** and the need for a suite of market mechanisms to ensure an orderly transition which maintains the high reliability standards;
- The reduced supply of **frequency control and ancillary services** (FCAS) coupled with an increasing demand for frequency control resulting from electricity supply and demand variability;

[5] CSIRO and Energy Networks Australia 2017, Electricity Network Transformation Roadmap, Final Report

- The reduced level of system **inertia** leading to more rapid frequency deviations which has resulted in consideration of the creation of new markets for inertia and **fast frequency response** (FFR) services; and
- The latent potential of the increased capability and uptake of **demand response** technologies to support the successful integration of VRE generators and the need for a mechanism that facilitates demand response in the wholesale energy market.

1.3 Opportunities for Innovation

1.3.1 The NEM Wholesale Energy Market

Overview

The NEM is a wholesale commodity exchange for electricity which covers the regions of South Australia, Queensland, New South Wales (which includes the ACT), Victoria and Tasmania. The NEM is an energy-only spot market where power supply and demand are matched in real time through a centrally coordinated dispatch process. Generators offer to supply the market with bid specifying the amount of electricity at specified prices for set periods and the Australian Energy Market Operator (AEMO) deploys the generators in 'merit order', i.e. with the cheapest bids being put into operation first.. Bids can range from the floor price (-$1,000/MWhr) to the market cap price ($14,000/MWh for 2016/17). Roughly 100 generators and retailers participate in the market.

A financial market sits alongside the NEM and involves retailers and generators entering hedging contracts to buy and sell electricity. These contracts set an agreed price for electricity and help to manage the risk of price volatility and provide long term investment signals.[6]

Market issues

The key challenges faced by the NEM wholesale electricity market, as outlined in the Finkel Review[7] are summarised below:

- **Dispatch and settlement misalignment.** The difference between the market bid and dispatch interval (5 minutes) and the settlement interval (30 minutes), based on technology limitations when the NEM was designed in the 1990s, opens the possibility for strategic bidding behavior potentially increasing the cost of supplying electricity in the long term. Alignment of these intervals is now possible, but could adversely impact the supply of financial contracts available to the market.

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[6] AEMO, National Electricity Market Factsheet, 2017.

[7] Independent Review into the Future Security of the National Electricity Market, June 2017, p78-83

- **Increased price volatility.** As VRE generators operate with no fuel costs, they typically bid into the wholesale market at zero which means that at high penetrations, when a VRE generator becomes the market price setter the clearing price can be zero or negative. Outputs from VRE generators can also drop suddenly in response to a change in the weather, requiring other generators to ramp up and down to balance system load and potentially increasing the cost of managing price risk. These characteristics are increasing price volatility in the wholesale market and creating challenging investment conditions for other generators.
- **Price impacts.** The interplay of relatively flat or decreasing demand and incentives for VRE generators to enter the market through the Renewable Energy Target led to a sustained period of relatively low wholesale spot prices. Uncertainty around emissions reduction policy also inhibited new investment in dispatchable capacity. The retirement of a number of generators then left the system operating in a state of undersupply which has put upward pressure on wholesale prices and had adverse implications for reliability. Increases to gas prices have also contributed to these price increases, and are likely to contribute to these prices persisting, despite additional generation capacity entering the market.
- **Disruptive technologies.** The increased number of VRE generators has highlighted the value of flexible capacity that can increase the firmness of these sources of electricity. Sources of flexible capacity such as demand response, battery storage and pumped hydro have the potential to significantly reduce the volatility of the wholesale market. This would impact the returns of other generators from the market – particularly peaking plants. As these disruptive technologies evolve, so will their impact on the wholesale market.
- **Electricity financial market liquidity.** As VRE generators are unable to determine the time or market price conditions under which they generate electricity, they typically enter power purchase agreements with parties who are able to offset the variable nature of their supply with other sources of generation. This means VRE generators have not typically entered into exchange traded contracts which contribute to liquidity. Coupled with the retirement of generators with dispatchable capacity and the increasing degree of vertical integration between generators and retailers into "gentailers" (who typically contributed less to the supply and trading of financial instruments due to their natural hedge), this has contributed to reduced liquidity in the electricity financial market. This has been particularly evident in South Australia resulting in forward contracts attracting a significant risk premium.

Market response

In response to these challenges there are a number of recommendations put forward within the Finkel Review[8], including;

- The implementation of a Clean Energy Target (CET) as a credible emissions reduction mechanism which minimizes costs for consumers, is flexible and adaptable, and can satisfy security and reliability criteria[9];
- A requirement for all large scale generators to provide at least three years' notice prior to closure;
- The development and implementation of a Generator Reliability Obligation (GRO) which should include undertaking a forward looking regional reliability assessment which accounts for emerging system needs, to inform requirements on new generators to ensure adequate dispatchable capacity is present in each region.
- The assessment by AEMO and the AEMC of the suitability of a "day-ahead" market to assist in maintaining system reliability.

In addition the AEMC have provided and initial position, in a directions paper, that the current 30 minute time interval for financial settlement for generators in the wholesale electricity market be reduced to five minutes, indicating that this would provide improved price signals for the efficient use of and investment in generation and demand-side technologies. A transition period in the order of three years is proposed.

Key innovation questions

- Is the NEM in its current form even necessary in a future with 100% renewables? How could we test this?
- How might a day-ahead market operate for the NEM? What would a transition path to this approach look like?
- What other market and technology innovations will impact the future NEM? (e.g. widespread adoption of corporate PPAs, the ubiquitous use of energy storage, the rise of distributed energy markets) How can we explore these impacts?

1.3.2 Frequency Control and Ancillary Services Markets

Overview

Ancillary services are used by AEMO to ensure the electricity system is managed in a safe, secure and reliable manner. These services ensure key technical characteristics

[8] Independent Review into the Future Security of the National Electricity Market, June 2017, p97-103

[9] This is the only Finkel Review recommendation that remains yet to be endorsed by COAG Energy Council.

of the system, including standards for frequency, voltage, network loading and system restart processes are managed and maintained.

The ancillary services markets include the delivery of frequency control ancillary services (FCAS), network control ancillary services (NCAS) and system restart ancillary services (SRAS). AEMO currently operates 8 separate markets for FCAS, while NCAS and SRAS are purchased under agreements with service providers. Additionally, transmission network service providers (TNSPs) have the primary responsibility to provide Network Support and Control Ancillary Services (NSCAS), while AEMO acts as the NSCAS procurer of last resort.

The main responsibility of the FCAS market is to ensure network frequency, the balance of supply and demand, is maintained within the operating band of 49.9 – 50.1Hz. The FCAS markets operate in a similar way to the wholesale electricity market, with FCAS providers (generally large-scale synchronous generators) bidding their services into the market.

NCAS and NSCAS markets are predominantly used to ensure voltage on the electricity network are maintained within prescribed standards and to manage power flow to within the physical limitations of the network.

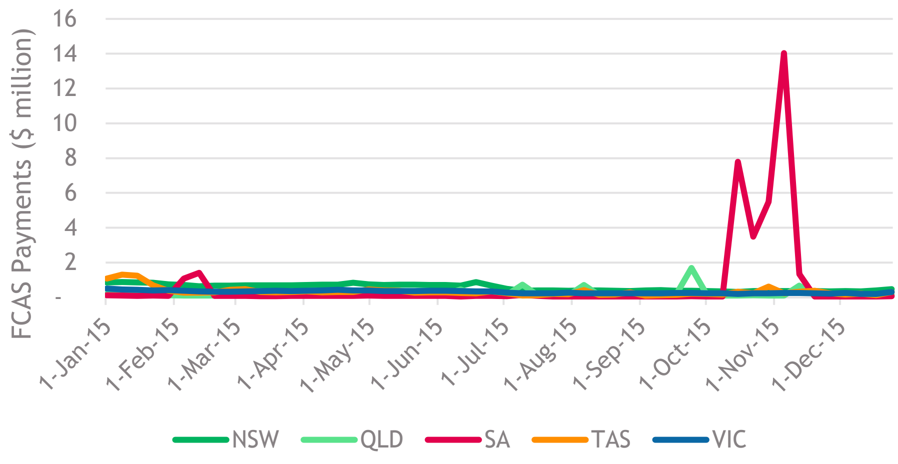
Market Issues

The price of ancillary services should in theory reflect the cost of availability (ensuring the capacity is available when required) and the delivery of the service. AEMO recovers these costs directly from market participants through the established settlement process.[10]

The need to actively plan for grids with a high penetration of VRE was highlighted in October and November 2015, when the interconnector between Victoria and South Australia failed. In addition to causing rolling blackouts across South Australia, it also caused a spike in FCAS payments, as shown in Figure 1.

Figure 1 – 2015 FCAS Payments

[10] AEMO, *Guide to Ancillary Services in the National Electricity Market*, April 2015



Source: AEMO

Part of the reason why the spike was so significant is that the number of providers of FCAS in SA is relatively limited, with only three registered in the state at the time. When the interconnector with Victoria is operating, this is not a problem, as there is sufficient competition in the provision of FCAS services across the NEM to supress prices (as highlighted by historically low FCAS prices across the NEM prior to Oct - Nov 2015). However, with the interconnector down, the lack of competition may result in inefficient market power being exhibited by FCAS providers.[11] AEMO has recognised that the limited number of registered participants in the SA FCAS market may result in high prices every time SA is islanded from the NEM. Based on an historical average in 2015, the expected cost for the total quantity of FCAS required in the NEM between 11 October and 10 November 2015 (35MW for SA) would have been around $0.47 million. The actual cost during the event was approximately $27 million.[12]

A number of studies[13,14,15] have found that distributed energy resources (DER) have the potential to provide ancillary services to electricity markets and could provide important additional capacity and market liquidity in a market with a large proportion of VRE.

In addition to issues around supply of FCAS in some markets, the Finkel Review also reported issues contributing to the increased instances of frequency violations. These issues related to the gradual alteration of governor settings on synchronous generators to increase the "deadband" (i.e. the frequency range within which the governors do not respond). This has the effect of reducing wear and tear on the governors but increases the risk of frequency variations. Requiring more generators

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[11] http://www.businessspectator.com.au/article/2015/11/2/energy-markets/are-intermittent-unreliable-wind-farms-causing-havoc-sa-again

[12] AEMO, *NEM - Market Event Report - High FCAS Prices in South Australia - October and November 2015,* December 2015

[13] AEMC, *Integration of Energy Storage - Regulatory Implications,* December 2015

[14] DNV GL, *A Review of Distributed Energy Resources*, September 2014

[15] ERCOT, *ERCOT Concept Paper on Distributed Energy Resources in the ERCOT Region,* August 2015

in the NEM to contribute towards frequency control through a tighter deadband would help reduce frequency variations and could improve system security and resilience.[16]

Market response

In response to these issues there are a number of developments to note:

- The Australian Energy Market Operator (AEMO), the Australian Renewable Energy Agency (ARENA) and South Australia's Hornsdale Stage 2 Wind Farm are collaborating to trial whether a wind farm can provide FCAS traded into the NEM while remotely controlled by AEMO.
- A rule change which came into effect on 1 July 2017 has introduced a new type of market participant – a market ancillary service provider. The enables aggregators of loads, who are not retailers, to participate in FCAS markets. Unbundling the supply of ancillary services from the retail supply of electricity is intended to increase levels of demand side participation in FCAS markets and increase the diversity of suppliers of ancillary services in FCAS markets.[17]
- The Finkel Review has recommended that by mid-2018, AEMO and the AEMC should[18]:
    - Investigate and decide on a requirement for all synchronous generators to change their governor setting to provide a more continuous control of frequency with a deadband similar to comparable international jurisdictions; and
    - Consider the costs and benefits of tightening the frequency operating standards.
- The AEMC has initiated a Frequency control frameworks review which will assess whether mandatory governor response requirements should be introduced[19].

Key innovation questions

- Is a market for FCAS the best approach for delivering these services? How could this be tested?
- How can the FCAS markets be enhanced?
- How can emerging technologies be better leveraged to provide FCAS services? How could this be demonstrated?

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[16] Independent Review into the Future Security of the National Electricity Market, June 2017, p58

[17] AEMC, Final Rule Determination, Demand Response Mechanism and Ancillary Services Unbundling, November 2016.

[18] Ibid, p61.

[19] AEMC, Frequency control frameworks review, Terms of Reference, July 2017

1.3.3 Inertia and Fast Frequency Response Markets

Overview

Synchronous generators (e.g. coal, gas and hydro) produce inertia, which provides for a more stable electricity system by easing the impact of changes in power system frequency due to rapid changes in generation or load profiles. Following a disturbance to the system, e.g. the trip of a load or generator, low inertia results in higher rates of change of frequency (RoCoF), which in turn may result in further disturbances across the system.[20]

Market Issues

VRE such as wind generators and solar panels do generally not provide any inertia (although kinetic energy is stored in the blades and the generator of wind turbines and can be extracted as a form of inertia-based FFR or “synthetic inertia”). As a result, in systems with a high proportion of VRE, the inertia inherent in the system is reduced, which may result in a less stable electricity system.[21]

Inertia can be provided by any region of the NEM, providing the relevant interconnector is operating. Modelling undertaken by AEMO for the South Australian (SA) market has found that there is sufficient inertia available across the NEM for the system to remain stable, assuming all interconnectors are operational.

Figure 2 – South Australia Inertia[22]

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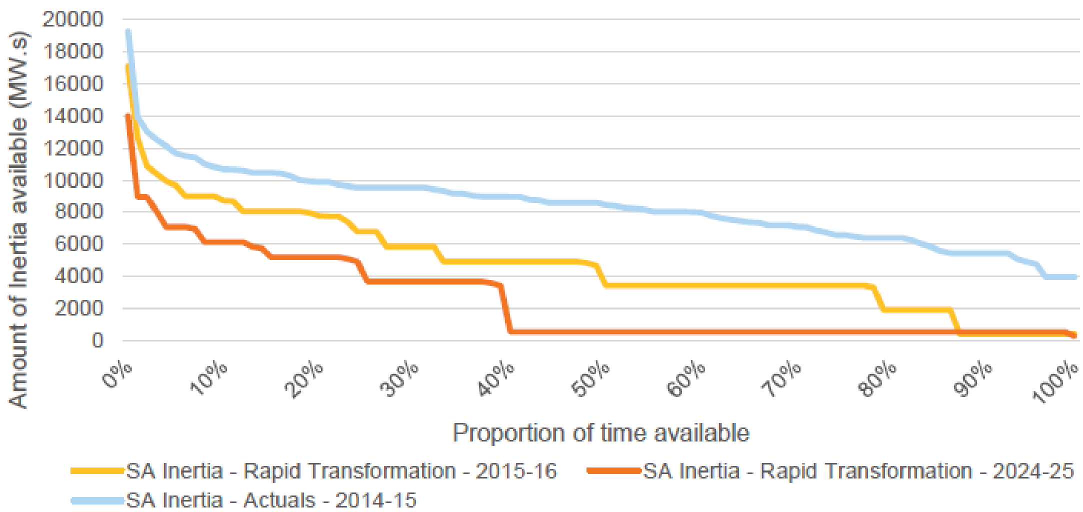
[20] AEMO, *National Transmission Network Development Plan,* November 2015

[21] Pieter Tielens, Dirk Van Hertem, *Grid Inertia and Frequency Control in Power Systems with High Penetration of Renewables,* 2012

[22] Rapid Transformation assumes that operational consumption follows the 2015 NEFR low scenario, and is lowered further by greater rooftop PV uptake (33.3 GW installed capacity by 2034-35, compared to 20.9 GW in the Gradual Evolution scenario) and a 40% penetration of residential battery storage (19.1 GWh installed capacity) by 2035. This scenario also assumes 20% of households own an electric vehicle (over 2 million electric vehicles) by 2035.



Source: AEMO

A potential problem may arise as more synchronous generators are retired, effectively reducing the inertia in the system, or when an interconnector goes down, resulting in a section of the NEM being islanded. In a state with a high proportion of VRE, such as South Australia, this would result in frequency deviation occurring more rapidly, impacting grid stability and increasing the need for FCAS to counteract the effect.[23,24]

Through their Future Power System Security (FPSS) program, AEMO have explored the potential of a Fast Frequency Response service in the NEM to help mitigate and manage high RoCoF. It found[25]:

- FFR is not a direct substitute for synchronous inertia, but enabling FFR services in the NEM may allow for frequency operating standards to be met with a lower level of synchronous inertia;
- FFR could be considered as a new type of FCAS and as part of an emergency response for managing extreme events;
- Response times for FFR vary based on the technology (batteries, flywheels and supercapacitors are faster than wind turbines) but it is would be prudent to build confidence in the deployment and response of FFR at slower response requirements before progressing to faster times as inertia levels reduce further; and
- Demand-side FFR resources are likely to be technically effective and cost efficient.

There is currently no market or incentive in Australia for market participants to provide inertia or FFR to the system, but the increasing share of VRE on the network has prompted some thinking in this area.

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23 Deloitte Access Economics, *Energy markets and the implications of renewables - South Australian case study*, November 2015

24 AEMO and ElectraNet, *Update to Renewable Energy Integration in South Australia*, February 2016

25 AEMO, Fast Frequency Response Specification, March 2017

Modelling undertaken by the University of New South Wales (UNSW) has found that a market-based approach for valuing inertia in the electricity system could be cost-effective solution. It used operational characteristics for a number of different generation technologies and technologies capable of providing inertia (synchronous condenser and energy storage) to simulate market conditions. The results showed that there is potential for an inertia market and that this could make existing thermal generators more cost-effective (by conversion to synchronous condensers), while RE generators capable of providing inertia (e.g. certain wind turbines) could become increasingly attractive.[26]

Market Response

The AEMC has responded to these challenges with a suite of recommendations contained in their System security markets frameworks review. With respect to inertia, the AEMC recommend[27]:

- Placing an obligation on transmission network service providers (TNSPs) to provide minimum required levels of inertia (or alternative equivalent services such as FFR, subject to AEMO's agreement); and
- Introducing a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum obligation on the TNSP.

It is also proposed that these recommendations be progressed as part of AEMC determinations on existing related rule change requests from the South Australian government and AGL[28]. The AEMC provides details for both TNSP and market sourcing approaches, with a stated preference for a market based approach.

With respect to FFR the AEMC recommended:

- A review of the structure of FCAS markets to consider:
    - How best to incorporate FFR services, or enhance incentives for FFR services; and
    - Longer-term to facilitate optimisation between FCAS and inertia provision
- Assessing whether existing frequency control arrangements will remain fit for purpose; and
- Considering obligations on all new plant to have fast active power control capabilities.

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[26] Ori Agranat, Iain MacGill, Anna Bruce, *Fast Frequency Markets under High Penetrations of Renewable Energy in the Australian National Electricity Market*, 2015

[27] AEMC, System security market frameworks review, Final Report

[28] Specifically these are the Managing rates of change of power system frequency proposed by the SA government and Inertia ancillary service market rule change requested by AGL.

In addition, the Finkel Review[29] recommended that a package of Energy Security Obligations should be adopted, such that by mid-2018, the AEMC should:

- Require TNSPs to provide and maintain a sufficient level of inertia for each region or sub-region, including a portion that could be substituted by fast frequency response services; and
- Require new generators to have fast frequency response capability.

It also recommends a future move towards a market-based mechanism for procuring fast frequency response (as detailed above) should only occur if there is a demonstrated benefit.

Key innovation questions

- What pilots or trials could be undertaken to better understand the ability of FFR services to compensate for reduced system inertia?
- How could a market-based mechanism for inertia be trailed and tested as part of the rule change process supporting its creation?
- How could the benefit of a market-based mechanism for FFR be proven or disproven?

1.3.4 Demand Response Markets

Overview

Demand response involves changes in the electricity usage of consumers from their normal consumption patterns in response to a price signal or incentive payment. It can involve the full range of customer types from residential customers to large commercial and industrial energy users and leverage the capabilities of a range of behind-the-meter assets including industrial plant, pumps, refrigeration units, embedded generators, storage and HVAC units. Increasingly, control of these assets for demand response purposes is becoming automated and remotely controlled via smart software solutions to optimise value and minimise disruption for customers.

Demand response can be used to avoid costly involuntary load shedding at times when the market is capacity constrained and it can be used to manage peak loads as a cheaper and faster way than building new generation or network capacity.

Market Issues

Demand response technology is advancing at a rapid rate, with remote communications and control devices and optimisation software designed to

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[29] Independent Review into the Future Security of the National Electricity Market, June 2017, p60

orchestrate fleets of aggregated distributed energy resources to optimise outcomes for customers.

Customer interest in and uptake of distributed energy resources is high and expected to remain that way as customers seek ways in which to control their energy costs in light of increasing prices. Yet, while the capability and capacity exists, it remains relatively untapped for the purpose of demand response. A study conducted in 2016 for the AEMC estimated that 2,000MW of load in the NEM would be responsive to a demand response price signal, only 235MW of demand response is under contract to retailers.[30]

In addition, in early February 2017 severe heat wave conditions led to AEMO directed load shedding in both South Australia and NSW, as well as public statements from Energy Ministers in several states calling for general demand response actions by customers. This highlighted the need for a more organised and co-ordinated approach to harnessing the potential of demand response in the NEM.

One form of demand response in the NEM exists in the form of AEMO's reliability safety net measure, the Reliability and Emergency Reserve Trader (RERT) mechanism. The RERT allows AEMO to contract for additional capacity reserves (either generation or load reduction), where there is a projected capacity shortfall. This mechanism has a number of shortcomings including:

- The Long Notice RERT, which enabled contracts of up to 9 months, is no longer available from 1 November 2017;
- The remaining Medium and Short Notice RERT options can only be contracted within a maximum of 10 weeks ahead of a projected shortfall placing AEMO at a sub-optimal negotiating position; and
- Participants are paid only if their contract is executed (typically demand response programs also include an availability payment), so there is insufficient incentive to encourage participation of distributed demand response aggregation services.

Market Response

In November 2016, the AEMC rejected a rule change request from COAG Energy Council to implement a demand response mechanism (DRM) to enable large customers to sell demand response in the spot market. This decision was made on the basis that[31]:

- Demand response can and already is happening on the NEM. There are no barriers to the continued proliferation of demand response that is currently underway; and

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[30] Oakley Greenwood prepared for AEMC, Current Status of DR in the NEM: Interviews with Electricity Retailer and DR Specialist Service Providers, 2016.

[31] AEMC, Final Rule Determination, Demand Response Mechanism and Ancillary Services Unbundling, November 2016

- The DRM would not result in overall savings to consumers through lower electricity prices.

Despite this, in June 2017, the Finkel Review recommended that COAG direct the AEMC to undertake a review to recommend a mechanism that supports demand response in the wholesale market, including a draft rule change proposal for consideration by COAG.

The Finkel Review also recommended an assessment by AEMO and the AEMC of the need for strategic reserve to act as a safety net in exceptional circumstances as an enhancement or replacement to the existing Reliability and Emergency Reserve Trader mechanism[32].

ARENA and AEMO are currently undertaking a trial of a new demand response initiative. The trial will run over 3 years and provide payments to customers (or their aggregators) from ARENA for becoming demand response enabled, and payments from AEMO (via the Short Notice RERT mechanism) if the customer is called upon to respond during an event. The NSW Government subsequently committed to contributing funds this trial. One of the stated objectives of this trial is to provide a proof of concept for how innovative and flexible demand side resources can help provide security and reliability[33].

Key innovation questions

- How can the lessons from the ARENA and AEMO demand response trial be applied to the recommendation to develop a new rule change proposal?
- How will the challenges raised in the assessment of the DRM rule change request be overcome by any new market mechanism?
- How can we ensure customers are well informed and protected when enlisting their assets in a demand response market?
- Could the demand response mechanism be linked into the Generator Reliability Obligation to form a broader market for flexible and dispatchable capacity?

1.4 International Case Studies

1.4.1 Day Ahead Markets

Day-ahead markets are present in most European power markets (Germany, Great Britain, NordPool) and the majority of North American power markets (PJM Interconnection, ERCOT, California Independent System Operator (CAISO)). In day-ahead markets, bids to trade volumes of electricity for each interval in a day are submitted and committed on the prior day. A schedule is developed from these bids

[32] Independent Review into the Future Security of the National Electricity Market, June 2017, p97-103

[33] ARENA, Media release – Demand side trial expanded for NSW, June 2017

committing certain generating units to run for given intervals, and instructing how they must dispatch. The day-ahead market is followed by a real-time balancing market where supply is dispatched to balance residual demand based on updated constraints. Unlike the NEM, where trading is settled in real-time, a high proportion of electricity trading volume is settled in day-ahead markets.

A key characteristic of day-ahead markets in Europe and North America is their ability to coordinate with fuel markets. In the United States, bidding into the day-ahead markets assists gas-fired generators in procuring and transporting gas supplies.

Broadly speaking, day-ahead markets may be considered a more efficient means for the market operator to manage reliability than a pre-dispatch process, as it diminishes the strategic withholding of capacity or disorderly bids. However, there are efficiency benefits from the flexibility of securing unit commitment closer to real-time. In existing day-ahead markets, moving the gate closure closer to real-time has been considered. The forward nature of day-ahead markets means generators can hedge against exposure to pricing and scheduling risks, which in turn reduces price volatility in the real-time market.

Day-ahead markets are also recognised to better facilitate demand-side participation compared to real time markets, with potential efficiency benefits.[34]

1.4.2 Inertia and Fast Frequency Response Markets

1.4.2.1 Texas

The energy regulator in Texas, ERCOT, launched a revamp of the local ancillary services market in 2013, in recognition of the changing energy mix of the system. In addition to its current suite of ancillary services markets, it is recommending the introduction of a market for a Synchronous Inertial Response (SIR) service. Through SIR, ERCOT would determine the amount of inertia required if large generators or loads in the network were to trip, which would then be sourced from the market. It recognises that inertia could be provided by conventional synchronous generators or from wind turbines, so called ‘synthetic inertia’. As ERCOT has determined that there is currently sufficient inertia in the system, it is still in the early stages of developing what an inertia market might look like, but this initiative represents some of the earliest regulatory thinking on this topic.[35]

1.4.2.2 Alberta and New Zealand

Both Alberta and New Zealand are examples of markets which contain large amounts of interruptible consumer loads. Commercial and industrial consumers in these markets have been technologically enabled so that interruptible load can respond quickly. Through independent aggregators, interruptible load can provide fast

[34] Electricity Authority of New Zealand - *Comparison of NZEM and Australian NEM, 2015*.

[35] ERCOT, *ERCOT Concept Paper – Future Ancillary Services in ERCOT*, September 2013

frequency response services within 0.2 seconds (Alberta) and one second (New Zealand).

1.4.3 Increasing ancillary services competition

1.4.3.1 Germany

Germany has committed to sourcing 80% of its energy needs from RE by 2050. To enable this transition, the German Energy Agency has launched a study into the future ancillary requirements of the grid. It recommends that the regulatory framework is reformed to allow small generation units (DER) to provide ancillary services such as frequency and voltage control to the grid.[36] Germany and other parts of Europe increasingly also utilise demand response (DR) as an ancillary service, allowing aggregators to contract loads to provide ancillary services to the electricity system.[37]

1.4.3.2 Hawaii

Similar progress is being made in Hawaii, with the Public Utilities Commission (PUC) looking increasingly at grid stability functions being provided by third parties (non-utility owned generation) and DER rather than the traditional generators. As part of this process, it has recommended that the provisions of essential grid services are unbundled to allow independent operators to provide these services (where cost-effective).[38]

1.4.4 Capacity Markets

1.4.4.1 Pennsylvania-New Jersey-Maryland Interconnect (PJM)

The ‘Reliability Pricing Model’ was introduced as a capacity market in the PJM in 2007. Here, the amount of capacity auctioned is determined based on forecast demand plus a reserve margin. The demand is expressed as a range that is a function of price; this helps promote cost-efficient outcomes because it procures a greater amount of capacity if the price is low, or a bare minimum amount of capacity if the price is high. The auctions is held three years ahead of the delivery year, with the auction period balanced between longer timeframes – to provide longer reliability and maximise competitiveness, and shorter timeframes - to facilitate more accurate demand forecasts. Initial auctions are conservative to minimise the risk of over-supply, while supplementary auctions address under-supply. Penalty regimes also provide incentives for resources to be available when required. Forward auctions in

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[36] German Energy Agency, *dena Ancillary Services Study 2030*, July 2014

[37] http://www.energypost.eu/restore-shows-demand-response-markets-europe-begin-blossom/

[38] Hawaiian Public Utilities Commission, *Exhibit A: Commission’s Inclination on the Future or Hawaii’s Electric Utilities,* August 2014

the PJM capacity market can also be used to manage generator retirements, with 3 GW of retired capacity forecasted upon the introduction of PJM's reliability pricing model.

1.4.4.2 Great Britain

Great Britain's capacity market was introduced in 2013, largely based on PJM's reliability pricing model. Here, the auction year is held four years before the delivery year.

Capacity markets are in place in the New York and New England power markets in the United States, and have been recently introduced in France, Italy, Ontario, Alberta and Western Australia.