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Mr. John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235
Submitted via www.aemc.gov.au

6 February 2018

Dear Mr. Pierce,

Response from EnerNOC to the Commission's **Reliability Frameworks Review – Interim Report** dated 19 December 2017 (EPR0060).

EnerNOC is a global provider of energy intelligence software and demand response services. We work with commercial and industrial energy users to enable dispatchable demand side flexibility, and offer that flexibility into wholesale capacity, energy, and ancillary services markets, as well as demand response programs offered by utilities. Locally, EnerNOC is a market participant in the Wholesale Electricity Market (WEM), the National Electricity Market (NEM) and the New Zealand Electricity Market (NZEM). EnerNOC's regional head office for Asia-Pacific is located in Melbourne.

EnerNOC is grateful for the opportunity to comment on the Commission's Interim Report. As an independent demand response aggregator, we have primarily commented on the topics of Strategic Reserve and wholesale demand response. The views in this submission are drawn from EnerNOC's recent experience as a market participant in the NEM:

1) Developing reserves for AEMO in the recent Long Notice RERT procurement
2) As a participant in the AEMO-ARENA demand response trial
3) As a Small Generator Aggregator (SGA)
4) As the NEM's first Market Ancillary Service Provider (MASP)

Please reach out to me with any queries related to this submission. EnerNOC would be glad to contribute further to the Commission's investigations into the incorporation of the demand side into the NEM's market frameworks.

Regards,

Matt Grover
Manager, Market Development | 03 8643 5907

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Strategic Reserves

Summary

EnerNOC is supportive of the continued role for a safety net in the NEM. Such a safety net could be implemented either by replacing RERT with a new Strategic Reserve mechanism, or by enhancing the existing RERT. In either case, the NEM's safety net (henceforth "Strategic Reserve") should adhere to the following design principles:

The Strategic Reserve:

1. Should be a permanent feature of the market rules, without a sunset clause
2. Should be able to be procured by AEMO at least six months in advance of the time period it is forecasted to be required
3. Should be available in a standing minimum quantity at all times, with AEMO having discretion to procure more if needed to meet its revised requirements
4. Should be procured in standard product(s) defined by AEMO
5. Should be procured in a transparent manner through a pay-as-clear auction
6. Should exclude participation of scheduled generators
7. Should be activated/dispatched only when a defined trigger condition is reached, indicating that the likelihood of involuntarily load shedding is intolerably high

The Strategic Reserve should be made permanent, and include a standing minimum quantity

The incorporation of a Strategic Reserve into an energy-only market is an acknowledgement that energy price signals alone cannot ensure that the Reliability Standard will be met in any given time period and/or that practical markets are not guaranteed to deliver politically acceptably combinations of reliability and cost. Recent publications by AEMO, the Commission, and the Finkel Panel all seem to acknowledge this possibility, and the statement is supported by recent events that have been well publicised.[1] It is for this same reason that most other energy-only markets worldwide operate with some form of standing Strategic Reserve. As weather events become more extreme and the forecasting of supply and demand becomes more challenging as more variable generation sources are incorporated into the NEM, the NEM's ability to accurately forecast its future needs will suffer.

The NEM must resist the temptation to decide that it won't need a Strategic Reserve in the future, based on forecasts available today. It must learn from past mistakes, and acknowledge that crises of overcapacity and low prices (i.e. 2013-15) can quickly turn into a crisis of capacity shortages and more involuntarily load shedding than the community finds tolerable (i.e. 2017). As evidence of the NEM's inability to perfectly forecast future needs, it is noted that:

[1] Specifically, the involuntary load shedding events of 8 Feb 2017 in South Australia, and 10 Feb 2017 in New South Wales. AEMO's ESOO report published September 2017 indicated increased potential for the current reliability standard not to be met in both states in FY 2017-18.

1) As recently as 2012, the Commission argued that RERT should be allowed to expire after its (then) sunset date of 30 June 2016, on the basis that "Market uncertainty is expected to have abated by 2016".[2]

2) As recently as 2016, many participants filed submissions encouraging the AEMC to allow RERT to expire after 30 June 2016. One submission argued that retaining RERT was unnecessary on the basis that the NEM "has exhibited extremely high reliability since its commencement" that "contract price outcomes have been sufficient to facilitate the entry of new supply", and "AEMO's latest public reports indicate that the reliability standard is not expected to be breached in any region prior to 2019/20".[3]

Of course, hindsight is 20/20 and the future is impossible to predict. However, prevailing views like those excerpted above have left the NEM with a RERT that is designed primarily to "avoid market distortions", with "usefulness to AEMO to avoid load shedding" a distant secondary concern. This issue manifested itself in February 2017 when, having no useful RERT available to it, AEMO was forced on two occasions to issue an actual LOR3 notice and instruct involuntary load shedding. Fast forward to summer 2017-18 and RERT – a mechanism that many participants just 18 months prior had argued should be completely removed from NEM Rules – is now being relied on by AEMO as a primary tool to ensure the Reliability Standard will be met.[4]

For these reasons, a Strategic Reserve should have a permanent role in the NEM, with a minimum standing quantity procured and available at all times.

AEMO should be able to procure Strategic Reserve at least six months ahead of its anticipated need

The Commission's decision in 2016 to remove AEMO's ability to procure RERT in Long Notice situations[5] was a short-sighted decision that will vastly reduce the effectiveness of RERT as a useful tool for AEMO, and as a cost-effective and reliable safety net for the NEM. AEMO's inability to signal its desire to procure reserves with more than ten weeks' notice is the largest weakness of the RERT framework. If the Commission chooses to amend RERT rather than replace it with a newly designed Strategic Reserve mechanism, this is the largest deficiency that should be addressed.

The problem is simple: if it can only procure RERT up to 10 weeks in advance of when it needs it, AEMO is less likely to be able to identify and contract sufficient reserves, and those it does find will be procured at higher cost and greater administrative expense than reserves procured in advance

[2] AEMC, Rule Determination, National Electricity Amendment (Expiry of the Reliability and Emergency Reserve Trader) Rule 2012 http://www.aemc.gov.au/getattachment/60a53a33-32b4-4ed0-a964-f2c2350cc8b6/Final-Determination.aspx, accessed 29 Jan 2018.

[3] ERM Power, submission to the AEMC Re: Extension of the Reliability and Emergency Reserve Trader Consultation Paper, 10 February 2016. http://www.aemc.gov.au/getattachment/43f71d81-c95d-4f8f-968b-8ee9305729ee/ERM-Power.aspx Accessed 30 January 2018.

[4] AEMO's September 2017 ESOO notes that "without planned actions via RERT provisions, there would be heightened risk of USE in Victoria and an increased potential for the current reliability standard to not be met."

[5] After 30 October 2017.

through a transparent mechanism. They are also likely to be less reliable, as there will not have been time for an orderly commissioning and testing process.[6] The role RERT plays in the NEM is similar to an insurance policy – to insure against the possibility that price signals alone will fail to bring forth adequate reliability, leading to the economy-wide cost of involuntary load shedding. As designed, RERT is effectively an insurance policy that AEMO is only permitted to try to purchase once it is almost certain it will need to claim on it. It is a difficult proposition for an insurance industry to exist to serve a customer like AEMO in this way.

To use health insurance as an analogy: if individuals were only able to take out health insurance policies once they began to feel sick, health insurance companies would have no choice but to charge outrageous premiums for such cover – as they'd have to build hospital bed capacity speculatively and keep it on standby (without any funding from premium payments) on the punt that one day, an individual would start to feel sick and the insurer would be able to recover its costs (of making the hospital bed capacity available) by selling them an outrageously expensive policy. Such is the paradox of RERT: because AEMO is only able to buy insurance once it is almost certain it will need to claim on the policy, AEMO is certain to pay unnecessarily high premiums for the reserves. After all, RERT provisions require that all RERT suppliers are capable of being dispatched (to increase generation or reduce demand), so all must invest in the ongoing capability to be dispatchable on a recurring and ongoing basis. However, the provisions require that they must be "not otherwise available to the market" (i.e. have chosen not to exercise their dispatchability in the energy market). Accordingly, the premiums (in the form of an availability payment) charged by RERT suppliers must reflect the fixed cost of building and maintaining that dispatchable capability, and the opportunity cost of forgoing its use in the energy market. This makes it likely that the reserves available to AEMO at short notice are likely to be the reserves that nobody else wanted – those reserves that are slowest and least reliable.

A standing Strategic Reserve with a minimum quantity, procured at least six months in advance of its intended utilisation, would be a better option. This would allow a viable insurance industry to invest in the requisite capacity to be available to serve AEMO, with the knowledge that they'll be able to recover their costs via AEMO's payment of a reasonable, regular premium that covers their costs of being available. As a further illustration this principle, please refer to the analogy in Appendix A.

Strategic Reserve products should be standardised

Another aspect of the RERT framework that requires revision is the ability for suppliers to negotiate bespoke commercial and operational terms with AEMO. The downsides of the status quo RERT arrangements are that bespoke reserve contracts (relative to a streamlined competitive procurement of a standardised resource) are:

- More time consuming and costly for AEMO to negotiate and contract
- More complex for the AEMO control room to dispatch

[6] We speak here from experience. In the recent 2017-18 RERT tender, EnerNOC received a signed reserves contract from AEMO on 23 October 2017, which obliged us to have a minimum quantity of reserve available on 1 November 2017. This extremely short timeframe required EnerNOC to begin developing reserves speculatively before we had any certainty AEMO would proceed with an agreement, and it severely limited the total quantity of reserve we were able to make available to AEMO.

- More complex for AEMO settlement teams to administer and settle against
- More difficult for DR aggregators to present and explain to energy users on an apples-to-apples basis[7]
- Less transparent to other market participants in terms of the firm quantities that exist
- More likely to cause market distortions
    - If market participants had the knowledge and confidence that all of AEMO's Strategic Reserve resources could only be activated with X minutes[8] (and no greater) lead time and would activate for a maximum of Y hours duration, it would give participants much greater confidence about how they commit their plant on days when LOR is forecast, as they would have much greater certainty around the timeline and trigger by which AEMO might decide to intervene and trigger what-if pricing.
    - The RERT procured in 2017-18 allowed suppliers to negotiate a number of commercial and operational parameters with AEMO, including:
        - Pre-activation lead time
        - Activation lead time
        - Max runtime
        - Min runtime
        - Availability windows/time periods
        - Max # activations
    - The result is a dog's breakfast of reserve contracts that AEMO must administer. This may have contributed to the somewhat confusing timeline of events on 30 November 2017,[9] when AEMO forecast a LOR2 from 15:30-17:00 but then activated an unknown quantity of RERT (and triggered intervention pricing) from 15:30-21:30.
        - As another example of this problem: AEMO informed participants[10] that one of its current RERT contracts requires pre-activation at least 24 hours in advance of being activated. This resulted in AEMO issuing a Market Notice[11]

[7] In the 2017-2018 RERT procurement, EnerNOC encountered situations where energy users were presented by commercial offers from competing aggregators. Each aggregator had negotiated different terms with AEMO, in terms of pricing structure (some agreements were in $/MW/yr, some in $/MWh) and operational characteristics (# hours max runtime, # activations per year, # minutes lead time, etc). This made explaining "how RERT works" to energy users unnecessarily complex, and made it difficult for energy users to understand which competing offer suited them best. Further, an energy user's efficient incentive is to enter an agreement with the aggregator who has negotiated the highest price from AEMO, yielding the highest commercial return for the energy user. In this way, AEMO may end up procuring the same RERT resources at greater cost, than if products were standardized, and aggregators' supply offers stacked and allowed to clear via auction.

[8] Or 30 minutes, or 10 minutes, etc. In EnerNOC's experience, the vast majority of demand response resources employed globally for reliability purposes (such as a Strategic Reserve) can and will choose to participate as long as the lead time (from notification by the system operator until the time the response is required to be fully delivered) is at least 30 minutes. In general, the shorter the lead time of the Strategic Reserve, the longer AEMO can afford to wait before deploying it, which affords market participants the greatest confidence that intervention intervals will be minimised.

[9] As detailed in the Commission's Interim Report, p.137.

[10] Verbal update given by AEMO at the Wholesale Consultative Forum on 31 January 2018.

[11] See Market Notice #60798, issued 17:00 on 18 January 2018.

on 18 January 2018, informing the market they may intervene the following day, 19 January. Requiring AEMO to foreshadow potential interventions so far in advance confused participants in this instance, and has potential to adversely impact the type of (desired) market response participants may decide to bring forth in the intervening time period.

- With a standing Strategic Reserve in which quantities and operational characteristics are standardised and transparent, there would be no need for AEMO to inform the market each time it "enters a reserve contract" (only when it activates/dispatches RERT, and at what quantity) – and participants would gain confidence:
  - By knowing exactly what intervention tools (and what MW quantities) AEMO has at its disposal,
  - By knowing exactly how long AEMO is able to wait before intervening by deploying the Strategic Reserve, and
  - That AEMO will wait as long as possible, and assess as much information as possible, before deciding to intervene.

Standardising the Strategic Reserves products and procuring them through a transparent pay-as-clear auction should allow for efficient procurement and transparent price discovery. With properly standardised products (and a compliance structure that ensures all bidders are credible, capable of, and incentivised to deliver on their commitments), the auction should be an objective, turn-the handle process. That is, a third-party should be able to look at the requirements that were published before the auction, and the list of bids (not published until after the auction), and work out exactly which bids should clear.

There is a sure-fire way to preserve investment signals when AEMO intervenes by activating RERT

One option the Commission could explore further is to set the spot price to the Market Price Cap for the duration of Strategic Reserves activation.[12] This would preserve investment price signals with absolute undeniable certainty, and also put AEMO under pressure only to intervene as late as possible, and only when involuntary load shedding would otherwise be almost certainly unavoidable. The Commission would want to examine this option fully to assess its expected impact on consumer price outcomes and ensure it doesn't introduce perverse incentives for those participants from whom AEMO desires a market response. However, we note that this approach has been adopted by the Strategic Reserves programmes in several European energy-only markets.

[12] In the same way that MPC is triggered when AEMO declares an Actual LOR3 condition. In this sense, AEMO would essentially be bringing forward the load shedding window, and converting some expected involuntary load shedding into voluntary Strategic Reserve deployment.

Wholesale demand response

Despite a theoretical 'efficient incentive' to pursue wholesale DR, too few retailers are doing so; innovation and competition are being stifled as a result

The AEMC's 2016 final determination on the Demand Response Mechanism rule change[13] correctly notes that retailers face a theoretical "efficient market incentive[14]" to develop and exercise wholesale demand response. This makes sense: when spot prices are extremely high, retailers can save money by buying less energy, and the most obvious way to buy less energy is by activating demand response within their retail customer base. The incentive is clear, so the question must be asked: why are so few retailers engaging in the practice, particularly in the residential space?

Many a consultation paper in the last year has cited the Mojo Power demand response trial[15] from 10 February 2017 as an example of how residential demand response can work. The trial was simple: on the hottest day of the NSW summer, Mojo sent a mass SMS to all their residential customers and offered a bill credit to any household that demonstrably reduced load. Mojo reaped the wholesale savings, and shared some of the benefits with participating households. The incentive was obvious, the technology was simple, and the results were well documented – so why hasn't every retailer in the NEM followed Mojo's lead? (Any why weren't they doing so long before 2017?) If the efficient incentive were working well in reality, we would see many retailers replicating Mojo's behaviour. However, EnerNOC is unaware of any other such retail programme (utilising load curtailment / shifting from residential customers, without a battery) in operation.

As example of the failure of the 'efficient incentive' to drive sufficient innovation in retailer-led wholesale demand response, we point to the 18 and 19 February 2018 in Victoria. On both days, a regional heatwave saw AEMO issue many LOR notices, and each day had a contiguous three-hour window where wholesale prices averaged above $3,000/MWh. Deploying DR in such a situation is a no-brainer, according to the efficient incentive theory. However, EnerNOC has not been able to find any evidence that any retailer requested energy conservation or load curtailment from residential customers. A survey of EnerNOC's 25 employees in Victoria revealed that our staff is spread across seven different electricity retailers at home, and all have interval metering, yet no staff member was contacted by their retailer and offered the opportunity to provide demand response on either day.[16]

EnerNOC suggests that the Commission look into why this is, and whether the 'efficient incentive' is operating in reality the way it is meant to operate in theory. EnerNOC suspects that the AEMC will find that the list of barriers that are preventing retailers from pursuing their efficient incentive include (non-exhaustively)…

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[13] http://www.aemc.gov.au/getattachment/68cb8114-113d-4d96-91dc-5cb4b0f9e0ae/Final-determination.aspx Accessed 6 February 2018

[14] AEMC, Final Determination, Demand Response Mechanism and Ancillary Services Unbundling, November 2017, p40

[15] AEMC, Reliability Frameworks Review, Interim Report, 19 Dec 2017, p109

[16] This includes EnerNOC staff who are participants in Powershop's ARENA's funded "Curb Your Power" DR programme.

- The ancient and inflexible billing and IT systems employed by many retailers.
- A lack of organisational capability and expertise relating to demand response resource development.
- An economic disincentive to invest in DR-enabling tools and procedures at customer sites, since retail contract durations of 12-24 months leave retailers with insufficient certainty they will be able to recover their investment of time and money, should the customer churn to a different retailer.
- Complex and perhaps perverse incentives faced by gentailers who own both generation assets and a retail book. A gentailer long on generation may earn more from selling expensive energy than they pay to the market in order to serve their retail book. In the long term, such a gentailer may have an incentive not to engage in activities that reduce spot prices (like wholesale demand response).

… and that all of these factors are hindering innovation on the demand side, to the detriment of consumers.

Why are retailers only getting involved with DR now?

The 'wholesale demand response' chapter of the Commission's Interim Report notes that:

> *"Recently, a number of retailers have offered to provide demand response in the AEMO and ARENA RERT trial, including Powershop, AGL and EnergyAustralia… Origin Energy has also announced a demand response trial. This indicates that retailers are increasingly using demand response."*[17]

While EnerNOC is encouraged that demand response's important role in the NEM is becoming more widely recognised and we are supportive of ARENA's initiative in this space,[18] we find the Commission's conclusion problematic for these reasons:

1) The demand response these retailers are developing for the ARENA trial is outside-the-market Strategic Reserve, not inside-the-market wholesale demand response. Further, it is AEMO who will decide to dispatch the ARENA-funded DR resource (or not), rather than the retailer itself.
2) If retailers have always faced an 'efficient incentive' to develop wholesale demand response, why are they only investing in DR enabling tools and capabilities now that taxpayer-funded ARENA grants have been made available to them?
3) Throughout the Interim Report, the Commission has made clear its view that wholesale demand response is preferable to demand response sitting outside the market in a Strategic Reserve – so we find it puzzling that the Commission's report seems to applaud retailers for accepting funding to develop outside-the-market DR capabilities that they (supposedly) face an efficient incentive to develop inside-the-market anyway.

[17] AEMC, Reliability Frameworks Review, Interim Report, 19 December 2017, p.124.
[18] EnerNOC is also a recipient of ARENA funding and a participant in the trial.

EnerNOC suggests that there is prima facie evidence that retailers in the NEM are not sufficiently motivated by their theoretical 'efficient incentive', and that their inaction is suppressing the demand-side innovation the NEM requires in order to ensure efficient wholesale energy prices and reliability. We suggest that the AEMC explore whether the incentive is working effectively in practice.

The big issue: DER owners/controllers need a new market framework to help them serve the NEM with dispatchable capacity

EnerNOC suggests that the task before the AEMC is less about creating a specific mechanism for wholesale demand response, and more about creating a market framework with trading relationships that allow DER owners/controllers to offer their capacity to the NEM's market(s), without needing to become the customer's retailer.

Today, energy users in the NEM (be them large or small, commercial or residential) have one (and only one) party through whom they are forced to interface in order to realise value from any behind-the-meter DER they own or control: their retailer. This must change if the NEM is to tap the potential of dispatchable DER and realise its distributed, low carbon future.

The most obvious and tangible near-term example of a forthcoming DER-based business model is the role of battery aggregators. Battery manufacturers (or battery control system manufacturers) will have the capability to control large distributed fleets of behind-the-meter residential battery capacity. These fleets of batteries will be capable of responding to high energy spot prices very quickly, and would be capable of registering as a scheduled generator, should the fleet reach the requisite size (in terms of MW capacity, as determined by AEMO) for doing so. Under today's market frameworks, if a residential battery responds to a high spot price by exporting energy (or simply reducing grid consumption) all the benefits accrue to the retailer. A battery manufacturer who wants to sell batteries to consumers on the basis of their wholesale market earning potential must establish commercial agreements with specific retailers who will accommodate this activity, and ensure that their customers remain with those specific retailers.

Requiring DER owners to churn on to specific retail suppliers in order to realise the full benefits of their DER would be a poor outcome that will stunt the growth of price-responsive DER capability[19] in the NEM, for these reasons:

- It's likely to enable predatory retail practices, forcing customers to stick with a single retailer for a long term in order to pay back a capital investment in DER.
- Retail competition in the NEM is insufficient to drive innovation in demand response and DER uptake. The AER's 2017 State of the Energy Market Report notes that "50% of customers have not switched their retailer or energy plan in five years". Similarly, large swathes of consumers in the NEM lack choice of retail supplier[20]. Such customers have no

[19] This can be thought of in much the same way as wholesale demand response.

[20] For example, as at June 2016, 88% of small customers in Tasmania remained on standing offers from the single government owned retailer. (AER State of the Market Report, May 2017, p.142).

choice but to hope that their single retailer invents an innovative DR product and offers it to them. If the retailer doesn't, that customer is out of luck and has no avenue for participation in wholesale demand response.

  - A better option would be if energy users had the option to install DER on their own, and contract with an aggregator[21] to extract value from being flexible in the wholesale market, irrespective of their retail supply arrangement (and without adversely impacting their retailer).

- We note that some retailers in the NEM do seem to be facilitating wholesale demand response from DER. The most obvious example is that of Reposit Power, a technology company that manufacturers a residential battery control system, and which reports it has forged commercial partnerships with three retailers in the NEM[22]. In order for a household (with a battery) to get value from buying a Reposit Power battery control system, it must also churn onto one of Reposit Power's retail partners, and remain with that retailer. The retailer can choose to dispatch power from its fleet of Reposit Power-controlled batteries when spot prices are high. In doing so, the retailer accrues a wholesale savings,[23] a portion of which the retailer passes on to the battery owner in the form of a payment (or a bill credit).

  The Reposit Power model is a creative utilisation of the NEM's existing market frameworks in order to extract value from employing DER for wholesale demand response, and we are in no way seeking to denigrate it. But those same frameworks are suppressing innovation and customer choice, for these reasons:

  1) To enable maximum uptake and optimal levels of customer choice, every DER fleet controller (like Reposit Power) in the NEM would have to sign commercial agreements with every individual retailer in the NEM – a requirement so burdensome that it will deter battery aggregators from entering the space.[24]

  2) Households with a Reposit Power controller and retail partner still only have one party to whom they can sell their wholesale demand response capability: their retailer. This retailer faces no price competition for the right to deploy each household's wholesale demand response capability. Diamond Energy's GridCredits100 plan reports paying households $1,000/MWh for energy dispatched from their batteries during wholesale demand response activations.[25] If deployed by a retailer from 16:00 to 18:00 on 18 February 2018 in South Australia (as Reposit

[21] For instance, the manufacturer of their battery or their battery control system.

[22] https://repositpower.com/gridcredits/ accessed 2 Feb 2018.

[23] i.e. an avoided expenditure.

[24] Indeed, it would appear that few competing Reposit Power-style business models have appeared in recent years. We suspect this is due to the requirement for technology service providers to work entirely through incumbent retailers (many of whom have such inflexible legacy billing systems that they would struggle to integrate such new technology) – and that this requirement is hindering innovation in the NEM. We encourage the Commission to look into whether this is the case.

[25] https://repositpower.com/gridcredits/ accessed 2 Feb 2018

Power has suggested its retail partners are likely to have done[26]), this would have saved the retailer $9,813/MWh on average over that timeframe. After paying households their $1,000/MWh share, the retailer should be pleased with the 90% margin they have pocketed on the wholesale savings provided by the household's battery.

A less restrictive market framework would allow any household with a dispatchable battery[27] to sell the battery's dispatch rights to the most competitive service provider, instead of being forced to accept take-it-or-leave-it offers from their single retailer. If given the option to do so, some households in the example above may have gained utility from being able to sell their wholesale demand response capability to a third party, and in doing so may have been able to secure more attractive commercial terms and a larger payment.

Customers lose when they can only sell to a single buyer

To illustrate this principle, we will speak to three of EnerNOC recent experiences as an independent demand response aggregator in the NEM:

1) **Our experience providing reserves to AEMO in 2017-18.** EnerNOC is one of at least 13 reserve providers AEMO has contracted with to provide reserves through its recent Long Notice RERT tender,[28] and one of eight participants in the ARENA-AEMO Strategic Reserve trial.[29] To fulfil our obligations in each, EnerNOC spent three months recruiting commercial and industrial energy users in Victoria and New South Wales to join our aggregated portfolio of demand response providers. In many instances, the energy users we approached had received competing solicitations for their services from other aggregators in the ARENA trial, and EnerNOC was forced to compete on price and other factors against other aggregators in an attempt to secure the rights to manage the customer's flexibility in the Strategic Reserve – and in multiple instances, we were forced to go back to energy users with a more competitive commercial offer in order to secure their participation.

   This is probably the first occasion in the history of the NEM[30] that energy users have enjoyed price competition for their demand response flexibility – where previously, they could only be approached about (wholesale) demand response facilitated through their current retailer (the 'single buyer'). EnerNOC's experience competing to provide energy users with the best

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[26] http://blog.repositpower.com/south-australian-households-act-as-big-battery-and-get-paid-to-save-the-grid. Accessed 2 Feb 2018. This example presumes Reposit Power's retail partners operate resources in South Australia – which we have no public visibility into. In any case, wholesale prices in Victoria were near identical on the day, so the example holds equally in both NEM regions.

[27] (Or equally, an energy user of any size with a flexible load)

[28] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Emergency_Management/2018/RERT-providers.pdf. Accessed 2 Feb 2018..

[29] https://arena.gov.au/blog/demand-response-4/ accessed 2 Feb 2018

[30] 2017-18 being the first year that AEMO has run a large mass-market RERT tender.

offer is exactly how demand response provision *should* work in the NEM: multiple parties should compete to give customers the best price. This is how demand response operates in most overseas markets, and how industry is incentivised to innovate. For example, EnerNOC operates large (1,000 MW+) demand response aggregations in both Korea and PJM,[31] and in both markets we routinely compete against other aggregators for customers, and sometimes lose prospective customers to aggregators who are willing to offer higher prices for demand response than us.

EnerNOC's experience in this section obviously relates to our participation in developing a Strategic Reserve resource, but the principle is entirely applicable to wholesale demand response as well: if the AEMC can create a framework that allows flexible loads and DER owners to sell their wholesale demand response capability to any party (instead of just their retailer), new independent aggregators will emerge with innovative business models, and they will compete with each other for the right to bring customers' distributed flexible capacity to market – and customers will win.

2) **Our experience as a Small Generator Aggregator (SGA).** EnerNOC has held an SGA licence since 2011, and has developed a fleet of dispatchable behind-the-meter generators that we operate under the SGA framework. At various times, we have leveraged this fleet to sell caps, engage customers on a spot-price share basis, and/or contracted the dispatch rights to other market participants. As the SGA, EnerNOC is effectively the retailer[32] for the meter on each generator – and so we have experience with selling and developing commercial wholesale demand response offerings, and have experienced firsthand the lack of incentive that retailers face to offer the most competitive rates: because a retailer is the 'single buyer' for an energy user's demand response capability,[33] the retailer's incentive is not to offer a payment commensurate with the wholesale value for the service, but rather to offer the lowest payment they feel the customer will accept in order to agree to participate in the demand response scheme.

3) **Our experience as a Market Ancillary Service Provider (MASP)**. As a real-word illustration of the innovation and increased competition the Commission can expect in wholesale demand response if it is able to introduce an effective and palatable framework to allow independent aggregators to participate, the Commission need look no further than what happened after it decided to implement the *Ancillary Services Unbundling* rule change. Below we offer a summarised timeline of events relating to that rule change.

[31] PJM is the market operator for 13 states in the Mid-Atlantic region of the United States. In both Korea and PJM, demand response is procured centrally in an auction by the Market Operator, and only deployed for reliability purposes.
[32] EnerNOC is the Financially Responsible Market Participant for the generator's NMI – often a child NMI on an embedded network, behind a boundary meter for which some other party is FRMP.
[33] Equally, be it a curtailable load or behind the meter standby generator.

Date	Action
Entire history of the NEM, pre 2017	Market rules allow retailers to bid aggregated demand response into the FCAS markets, but prohibit independent aggregators. However, no retailer ever choose to do so,[34] and the NEM's ancillary services remain almost exclusively provided by large scale generators.
November 2016	The AEMC makes a Final Determination to make the *Ancillary Services Unbundling* rule.
July 2017	The new rule takes effect.
October 2017	The first registered MASP (EnerNOC) submits its first bids into the Contingency Raise FCAS markets.
January 2018[35]	New entrant MASP is supplying 4.4% of the NEM's Contingency Raise FCAS (and growing), reducing the market share of incumbent generators.
Early 2018	A second prospective MASP (Hydro Tasmania) has applied to AEMO and will presumably further increase competition in the FCAS markets in 2018.[36]

For the first 20 years of the NEM, retailers showed they were uninterested in (or incapable of) developing demand response resources for purposes of ancillary services. Less than a year after the AEMC *announced* it would allow independent aggregators access to the FCAS markets, two aggregators had applied to enter the market, and one of them had fully developed a service offering, registered with AEMO, and carved out a 4.4% market share from incumbent suppliers.[37]

In the entire history of AEMC rule changes intended to increase competition in the NEM's markets by removing barriers to entry for new participants, the Commission would be hard pressed to identify a rule change that has achieved its intended result as quickly as the *Ancillary Services Unbundling* rule change.

Once the Commission unbundled the provision of ancillary services from retail supply, aggregators arrived and began innovating immediately, resulting in increased competition and downward pressure on wholesale ancillary services prices[38]. EnerNOC submits that aggregators will arrive,

[34] In this timeframe, only a single energy user ever bid in FCAS via demand response: the Portland Smelter, with bids facilitated by the residual SECV participant.

[35] Specifically, the R6, R60, and R5 services over the 1 Jan – 15 Jan 2018 time period. EnerNOC analysis of MMS data.

[36] AEMO, NEM Registration and Exemption List, accessed 10 Jan 2018

[37] Further, this real world example is illustrative of the speed at which aggregators can conceptualise, commercialise, and operationalise 'virtual power plants' comprised of DER.

[38] Indeed, Contingency Raise FCAS prices have reduced since EnerNOC's entry into the market in October 2017, though it is difficult to determine how much of the price softening is due to the increased supply from EnerNOC, vs. the behaviour of other market participants – including the Hornsdale Power Reserve, which since its entry to the market in December 2017, has been bidding its full Contingency FCAS capability into the markets at $0.

innovate,[39] and have a similarly disrupting impact in the wholesale energy market, if the AEMC is able to introduce a suitable framework to unbundle provision of an energy user's wholesale demand response capability from provision of their retail supply arrangement.

About EnerNOC's aggregated Contingency Raise FCAS resource:

EnerNOC's FCAS resource is comprised of distributed, aggregated switching controllers installed at commercial and industrial energy users' facilities throughout the NEM. The MW quantities that EnerNOC bids into the market vary by trading interval, in line with customers' production schedules and real-time demand. To date, EnerNOC has offered and cleared as much as 14/60/71 MW in the R6/R60/R5 FCAS markets[40].

EnerNOC's participating customers come from the cold storage, industrial, and forest products manufacturing sectors, and also includes behind the meter batteries. Of the controllers capable of responding fast enough for the R6 market, the vast majority provide a 'Fast Frequency Response' in less than 250ms.

The resource will continue to grow over time (in terms of MW capacity, and market share) as EnerNOC incrementally adds energy users to the aggregation.

[39] One such innovative business model under a new framework would likely involve independent aggregators selling caps, and defending those caps with wholesale revenues earned by facilitating load reductions in the energy market. In this way, allowing aggregators to compete is likely to increase liquidity in the cap markets.
[40] As at 6 February 2018

‘Unbundling energy from energy’ is already happening, and is not problematic

The Commission’s Interim Report comments that “Separating the two services - energy and wholesale demand response - would in a sense be trying to disaggregate energy from energy.”[41] We submit that doing so is not problematic, and has already been occurring successfully and without complaint under the Small Generator Aggregator framework. The below table details how this unbundling is already occurring, and how it might occur in the future under a new wholesale demand response aggregation framework.

WHO DOES WHAT (BTM = behind the meter)	SGA Framework	Hypothetical future third-party aggregator framework
Configures, registers, controls BTM activities	Aggregator	
Responsible for settling gate NMI with AEMO	Retailer	
Responsible for settling BTM energy with AEMO	Aggregator	
BTM energy measured by (per trading interval)	Sub-meter on generator	Baseline minus actual
Retailer made whole for BTM energy via	Subtracting negative consumption on child NMI results in “BTM energy addback" onto parent NMI	Settling on baseline energy in trading intervals declared by the Aggregator results in “BTM energy addback” onto parent NMI
Does retailer sell less energy to customer as result of BTM activities?	No	
Is retailer aware of customer's BTM activities?	Only if they care to dig into settlement data	
Retailer procures hedges, charges customer for them, as if BTM activities were not occurring?	Yes	
Can AEMC guarantee benefits > costs to customer for participating in scheme?	No	
Responsible for proving to customer they're better off for participating in scheme:	Aggregator	
Retailers had to upgrade billing systems to accommodate BTM settlement framework?	Yes, to accommodate a market generator within an embedded network	Major sticking point from 2015 DRM rule change proposal
Resource behaviour equivalent to that of a:	Non-scheduled market generator	

[41] AEMC, Reliability Frameworks Review, Interim Report, 19 December 2017, p.128.

Wholesale demand response is capable of participating as a scheduled resource

We note that the last time the Commission offered views on a hypothetical third-party aggregation framework,[42] the Commission was of a view that unscheduled resources were undesirable in that they introduced market distortions because they could only react to spot prices, and could not directly contribute to setting them. As the Commission is considering future frameworks to facilitate wholesale demand response, it should consider that aggregated demand response *could* participate as a scheduled resource, and submit bids into NEMDE, if required. The NEM has never seen such a resource previously, but this is only because no provision has been made for such participation, and independent aggregators have been prevented from participating and innovating in the wholesale market for energy. We also note that the original vision for a Demand Response Mechanism (as conceived by the Commission and recommended to COAG Energy Council (then SCER) in 2012) was a scheduled mechanism.

If we're going to have a cost-effective NEG, the Commission must first crack the nut on wholesale demand response and access for third-party aggregators

This Reliability Frameworks review is a timely opportunity for the Commission to set out a framework that unlocks access for third-party aggregators to develop wholesale demand response in the NEM, and in doing so, set the proposed National Energy Guarantee (NEG) up for success.

In the Energy Security Board's advice from 13 October 2017, the Board describes a proposed "Reliability Guarantee" that would include (emphasis ours):

> *"an obligation on retailers to meet a percentage of their load requirements with flexible and dispatchable resources, that is, resources that can be* ***scheduled by the market operator****… The resources which comply with the system needs would be carefully defined and include any form of technology, generation, batteries, and* ***demand that can respond to a request by the operator to increase or decrease their output over a defined time interval****."*[43]

EnerNOC is encouraged that the Board has given due consideration to the demand side in its early public commentary relating to the proposed NEG. However, dispatchable demand response will continue to play only a minor role, if, in order to meet their Reliability Guarantee obligation, retailers are only able to develop demand response from within their current retail customer base (as is the status quo today).

For the NEG to facilitate meaningful quantities of wholesale demand response incremental to today's status quo, retailers must be allowed to buy dispatchable demand response resources from independent aggregators, and use it to meet their obligations under the Reliability Guarantee. Further, those aggregators must be able to develop and aggregate that demand response from any energy user in the NEM, regardless of the energy user's current retail supply arrangements.

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[42] In its Final Determination on the *Demand Response Mechanism and Ancillary Services Unbundling* rule change proposal, November 2017.

[43] ENERGY SECURITY BOARD (ESB) ADVICE ON A RETAILER RELIABILITY, EMISSIONS GUARANTEE AND AFFORDABILITY, 13 October 2017

Achieving this outcome will require the Commission to introduce a new framework that facilitates third-party provision of wholesale demand response. Failure to do so will ensure that the market-wide cost of fulfilling the NEG's Reliability Guarantee is costlier than need be.

The Commission's description of wholesale DR vs emergency DR in Figure 6.1 is note reflective of reality

Figure 6.1 from the Commission's Interim Report indicates that:

- Demand that has a marginal benefit of consuming greater than the market price cap, but less than the cost of involuntary load shedding, should provide emergency demand response (i.e. outside-the-market Strategic Reserve)
- Demand that has a marginal benefit of consuming less than the market price cap should provide wholesale demand response (i.e. inside-the-market price response, facilitated through a retailer).

This understanding does not reflect reality for the following reasons:

- There are a multitude of reasons why many demand-response capable energy users fall in the 'emergency' category instead of the 'wholesale' category, including those mentioned in this submission that relate to barriers energy users face in accessing demand response via their 'single buyer' retailer. In the context of the ARENA trial, some of the energy users EnerNOC has contracted are capable of participating in 'wholesale' demand response, but have simply never been offered the opportunity to do so by any retailer. As such, their introduction to demand response in the NEM falls in the less desirable 'emergency' category.

- AEMO has reported[44] that the majority of the expected cost of the Long Notice RERT it has procured for 2017-18 is availability costs, and that most RERT suppliers'[45] 'strike price' for utilisation is below the MPC. This reality would seem to contradict the theory represented in the Commission's Figure 6.1, whereby energy users would only choose to participate in a Strategic Reserve at strike prices > MPC. It suggests to us that the opportunity cost of the types of load that will choose to participate in demand response is well below the MPC, but also that demand response requires a firm availability payment to cover the investment and ongoing costs of making itself available. This is consistent with our prior point that nobody provides insurance without a premium payment. Generators get around this through selling caps: the premium provides the availability payment. No such option is available to load, even if their short run marginal cost is well below the MPC. Accordingly, for many energy users in this category, the 2017-18 RERT tender is the first opportunity they have had to invest in and serve the NEM with demand response.

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[44] AEMO, verbal update to attendees at the NEM Wholesale Consultative Forum, 31 January 2018.

[45] AEMO has indicated that the majority of the Long Notice RERT it has procured for 2017-18 is demand response.

Appendix A

Analogy: Why it's costlier and less reliable to wait and only stand up a Strategic Reserve at the last possible minute

If you were designing an off-grid home, you would size your solar panels and storage capability to meet your expected needs, with knowledge that you face a tradeoff between cost and reliability. You could oversize your solar + storage to guarantee power supply through all conceivable extreme weather conditions (i.e. prolonged cloudy periods), but this would dramatically increase the cost of your energy supply system. More rationally, you will probably choose to accept that in rare situations (say, .002% of the year) you'll have insufficient power and will have to tolerate the inconvenience and cost of not being able to power your home's lights, devices, and appliances.

So how will you prepare for those rare periods without power? You could choose to suffer through and go about your daily activities in the dark, but a more sensible idea would be to invest in a battery powered torch, and to keep it available in the closet. You would have to make a small up-front capital investment in a torch, and incur small annual costs to replace the batteries and test the torch – with knowledge that you'll only retrieve it from the closet and switch it on in those rare situations where your home's supply is insufficient. Importantly, your decision to procure and maintain a torch has no material impact on the manufacturers and suppliers of your home solar and storage system: you'll continue to lean on (and pay to maintain) their products and services despite your capability to rely on your torch in rare situations.[46] These service providers will continue to invest in developing and selling cutting-edge off-grid home energy systems, because they understand and have confidence that your torch isn't a replacement for their products and services.

So, WHEN should you buy a torch? One option is to buy the torch well in advance of a period of expected cloudy weather – you might buy a torch when you're at the shops and they're on sale in the summertime, in anticipation of cloudy periods that might arise next wintertime. This would ensure you have time to shop around for the most effective torch for your needs and budget (brightness, battery life, cost, etc.), and will ensure you're able to buy a torch at the cheapest prevailing market price. Conversely, you could decide to wait until a problem is imminent, and rush to the store to buy your torch. At this time, your neighbours are likely to be doing the same – increased demand for torches has led to reduced availability in shops – shelves are empty and merchants are charging exorbitant prices for the torches that remain, and there's a lesser likelihood you'll find a torch model that has the exact brightness and battery life you require to meet your needs. You're likely to end up with a torch that doesn't meet your exact needs, and pay a price that diminishes the utility you receive from owning the torch. In this situation you're still glad you bought the torch because it minimises the cost of putting your daily life on hold by living in the dark (i.e. the benefits you receive from the torch still outweigh the cost and hassle of procuring it), but you find yourself wishing you had bought the torch in advance.

[46] It could be argued that, if you knew that no torch would be available, you might invest in more solar and storage capability to further reduce the likelihood of running out of supply. The manufacturers would certainly like this, but it would not be economically rational or efficient.

Such is the role a Strategic Reserve plays in an energy-only market. To minimise the economy-wide costs of involuntary load shedding, it's sensible to ensure some reserves are available – and the cheapest and most efficient way to procure those reserves is well in advance. Importantly, because industry knows the reserves will only be employed at the last possible instance to prevent load shedding, investment in supply-side resources will continue unimpeded.