Thursday 12th September

Rachel Thomas
Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

Lodged via AEMC web-portal

Dear Rachel

Re: ERC0352 Consultation on Draft Determination on Integrating Price Responsive Resources (IPRR) into the NEM

The Clean Energy Council (CEC) welcomes the opportunity to provide feedback to the Australian Energy Market Commission (AEMC) on the Draft Determination for the Integrating Price Responsive Resources (IPRR) into the National Electricity Market (NEM) Rule Change.

The CEC is the peak body for the clean energy industry in Australia. We represent and work with Australia's leading renewable energy and energy storage businesses, as well as a range of stakeholders in the National Electricity Market (NEM), to further the development of clean energy in Australia. We are committed to accelerating the transformation of Australia's energy system to one that is smarter and cleaner.

Consumer Energy Resources (CER) will play a major role in achieving Australia's decarbonisation ambitions and meeting our renewable energy goals. Predictions in the latest Integrated System Plan (ISP) publication from the Australian Energy Market Operator (AEMO) forecast that by 2032, over half of the homes in the NEM are likely to have rooftop PV systems, rising to 65% with 69 GW capacity by 2050. This will make rooftop PV the largest source of electricity generation in the NEM. The integration and management of that level of distributed generation is forecast to require almost 30GW of distributed storage and flexible demand.

The CEC recently released our own CER Roadmap "Powering Homes, Empowering People"[1], which found that meeting the AEMO ISP CER projections would deliver over $22bn in savings for Australian taxpayers; create 18,200 jobs; and result in up to 3.8m more homes and businesses with orchestrated batteries.

[1] https://assets.cleanenergycouncil.org.au/documents/resources/reports/Powering-Homes-Empowering-People-CER-Roadmap.pdf

The work done by the AEMC and AEMO in respect of the Integrating Price Responsive Resources Rule Change will play an important role in encouraging increased orchestration of CER. The CEC response aims support the Rule Change to be as successful as possible, encouraging a shift from unscheduled price-responsive assets to voluntary scheduled resources (VSR). We agree with all the points made by the AEMC in the Draft Determination that this should remain a voluntary mechanism, and that many customers are unlikely to want their device dispatched for market purposes.

We see customers falling into three broad categories – first movers (including those customers currently in a Virtual Power Plant (VVP)) that are willing to accept a smaller financial reward; a majority of customers who will primarily be influenced by the level of financial reward attached to their system being dispatched (and the lack of perceived impact on their own needs); and those that have purchased CER purely for their own use and will not be willing to participate in dispatch regardless of the level of financial incentive attached.

The second category of customers is the one that will benefit most from a successful development of the IPRR Rule Change. It is worth noting that this category will also include customers, and market participants, who choose to take a lighter approach to dispatching assets – using systems purely for contingency Frequency Control Ancillary Services (FCAS) and some energy responsiveness. This continued flexibility is essential, and the CEC would not support any future shift to the VSR model being mandated for all orchestration. Market participants should retain the choice regarding which markets they participate in, and how scheduled they want orchestrated CER within their portfolio to be.

The Draft Determination fully acknowledges the risks and costs associated with scheduling CER and the scale of engineering work necessary for a successful implementation of the IPRR Rule. The CEC believes that the long-term success of this Rule Change will rely on two things:

- Incentive structures; and
- Operational features (or keeping the “scheduled-lite” functionality as “lite” as possible whilst maintaining system operational integrity)

In response to point two, the CEC has provided some considerations relevant to the actual Rule Change, though we acknowledge that the majority of the implementation work will sit with AEMO, and the potential challenges will likely only become known as work commences on AEMO documentation, and AEMO starts with the onboarding and trials for market customers. Continued work with interested market participants and maintaining a level of flexibility to adapt will be key to resolving this point.

If you have any queries or would like to discuss the submission in more detail, please contact Emma Fagan at efagan@cleanenergycouncil.org.au.

Kind regards,

Emma Fagan
Acting Director of Distributed Energy
Clean Energy Council

Incentive Structures

Work on a Federal Government incentive program

A major factor in determining the success of the program will be the incentive structures attached. AEMO and the AEMC need to find the right balance in providing a strong enough incentive to drive uptake, while also managing the costs.

For this reason, the CEC is very supportive of a joint work-program with the federal government to create an incentive scheme that goes well above the proposed $50m in incentives, through an AEMO tender process. While this is a good starting point, and we agree with the position of the AEMC that it is not an ideal incentive structure, it currently is unlikely to be significant enough to shift customer mindsets, or market participant, mindsets and drive uptake.

The CEC is very supportive of additional work being done on establishing a new incentive program – either through the Australian Renewable Energy Agency (ARENA), the Capacity Investment Scheme (CIS), or as part of a larger, alternative Home Battery Subsidy Program similar to that recommended by the CEC[2]. We are relatively agnostic on what a federal incentive program should look like.

We also do not think that an incentive program and the CIS are necessarily mutually exclusive. The CIS provides a helpful price floor for market participants and may make participation in dispatch mode more appealing once market participants have a better idea of the market value from participating in markets that CER and VPPs have previously been excluded from (this is considered in more detail below). Incentives will provide an important bridge in creating that initial uptake while these market revenues are unclear.

Australia has a long-history with incentive schemes changing market dynamics when it comes to new technology types – including using incentives to drive customer participation in VPPs. South Australia has significantly higher VPP capacity registered with AEMO currently than any other state[3]. This is largely driven by the SA Home Battery Subsidy Scheme, which both provided an upfront incentive for residential storage systems, as well as advertising available VPPs compatible with each approved battery. This shows how effective a new federal incentive program has the potential to be in driving increased uptake in the dispatch model.

A key consideration in designing a new scheme should also be the consideration of the incentive value offered to participants versus the market benefits created. The $50m in incentives provided over two tender processes, represents a very small fraction market value that will be achieved through increased orchestration. The work completed by Intelligent Energy Systems (IES) for the AEMC “Benefit Analysis of improved integration of unscheduled price-responsive assets into the NEM” shows a benefit of $1.8bn in improving orchestration of unscheduled price-responsive resources. The Draft Determination also notes that these efficiency gains are understated, and that the Rule Change is likely to lower spot prices by $12-13bn.

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[2] It's time to back home batteries: Home battery incentive would reduce cost of living | Clean Energy Council
[3] Using VPP capacity registered with AEMO as ancillary services as a proxy, South Australia currently has >3X the capacity registered than the next largest state. Note this does not include demand response capacity.

The ratio of incentive payments to capacity also seems low when considering other recent federal incentive schemes. The ARENA and DCCEEW funded federal Community Battery Incentive program has so far allocated $172m for up to 300MWh of installed community storage capacity[4]. Conversely, AEMO projections for aggregated BTM storage are 8,160MWh installed capacity by 2030[5]. As it stands, the funding amount suggested for driving increased orchestration of CER is one quarter of that available for community storage funding, even though the total MWh capacity of installed aggregated energy storage is much higher.

The CEC recommends AEMO and the AEMC continue to work with the Federal Government to establish an incentive program that more closely aligns to the funding of other federal schemes to fully recognise the lasting market benefits that will be provided by increased orchestration of CER. This should be considered as a broader Home Battery Incentive Scheme with dedicated incentives for orchestration / VPPs.

Costs for aggregators

The incentives for participation also need to be designed in a way that both offsets the costs for aggregators and adequately rewards customers for enabling orchestration of their CER for market purposes. The current proposed AEMO tender process would see AEMO setting the price cap for each tender which would be "half of the $/MW of the market benefit an additional MW is expected to generate". Importantly this only considers the market benefits likely to be generated in a single year of orchestration, while the benefits are assumed to continue over the life of the CER (while it remains dispatched in market). The costs for market participants will also endure over the life of VSR asset.

When considering both the costs to market participants and aggregators, and the expected costs to aggregators to participate in dispatch mode, there is a relative level of unknown that will only become apparent once AEMO testing has started.

The AEMC highlights several of the costs that will need to be considered – including SCADA-lite implementation, and market fees. Market participants will also need to manage the engineering build-out and integration with AEMO systems, as well as ensuring appropriate resourcing for market participation and ongoing compliance.

Customer incentives

In addition to the cost recovery from market participants, individual end-use customers will also need to be incentivised to enable their CER for dispatch. Creating the right customer incentive will be one of the more critical elements determining the success of the Rule Change, and total uptake of CER orchestrated for dispatch.

A contributing factor in the relatively low levels of VPP participation to date appears to be the disconnect between customer expectations on incentives, and the incentives offered by market participants. As part of their Project Edge work, AEMO produced a report "Summarising key customer insights into

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[4] $29m allocated through the Business Grants Hub for ~22MWh of installed capacity as per the DCCEEW landing page - Community Batteries for Household Solar program - DCCEEW; and $143m for Round 1 ARENA funding for up to 281MWh of installed capacity per the ARENA media release ARENA funds national community battery roll out - Australian Renewable Energy Agency (ARENA)

[5] AEMO ISP "2024 Inputs and Assumptions Workbook" – Step Change Scenario based on total NEM aggregated energy storage MWh quantities in 29/30

perceptions of and experiences with Virtual Power Plants"[6]. This report made the following points on customer perceptions:

- Consumers might like the VPP concept, but they're lukewarm about joining a VPP.
- Of the outcomes that mattered most to consumers, DERs and VPPs were seen as helping to achieve only one: saving money.
- Consumers had very high expectations about how much money they would save from joining a VPP.

Based on that report, customers expect approximately $1k in annual bill savings/ incentives from joining a VPP. This is on top of the broader self-consumption benefits (some of which will be reduced through participation in central dispatch). Current VPP offerings in Australia range from roughly $200 per year to up to $450 per year[7], this indicates a gap in the order of $600+ per year that will need to be bridged through a combination of additional in-market benefits and through an effective incentive framework attached to the program.

As noted above, a strong incentive program will likely to be necessary to bridge the market revenue gap in the short-term while market participants adjust to broader market access. The CIS may then provide a good option as an enduring scheme to continue to support customer interest. It is also likely that customer expectations around annual incentive payments will reduce as they become more comfortable and educated on how their CER responds in dispatch.

[6] Presentation Heading Here (aemo.com.au)

[7] Based on the Solar Quotes VPP comparison table which is available at - Virtual Power Plant (VPP) Comparison Table - SolarQuotes. Note that these benefits only consider the VPPs offering annualised payments. There are also alternative customer incentives such as up-front hardware discounts, increased feed in tariffs for grid exports, or zero-bill models. These may be offered in addition to, or as an alternative to, annual bill credits.

Consideration of in-market incentives

The Draft Determination provides a good summary of the range of additional markets that orchestrated VSR will be able to access. The extension to regulation FCAS market and access frequency performance payments will make the NEM the first market globally which will provide full market access to orchestrated CER.

However, this may not in itself, be enough to drive participation in the dispatch mode – at least in the short-term. The value of frequency performance payments is not yet known, and other future market projections are similarly not able to be factored into revenue projections and associated customer incentive structures.

Market participants may also be conservative in their view of additional market revenues that may be earned, based on declining Regulation FCAS value.

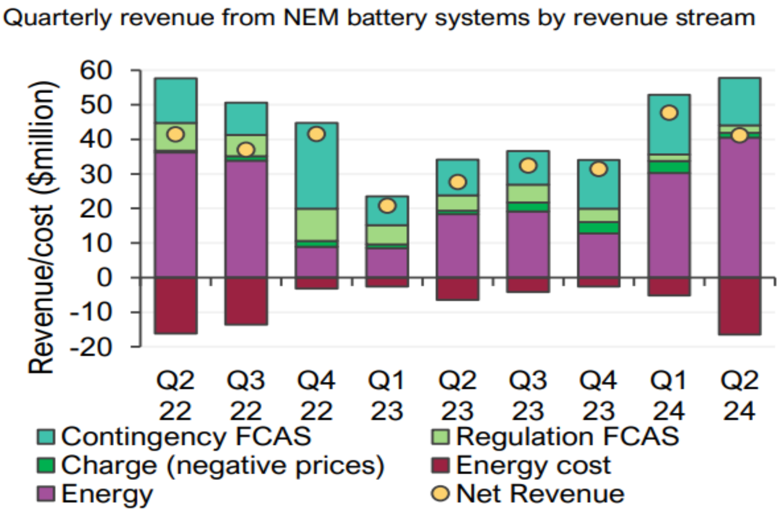

Figure 1: AEMO revenues from utility scale batteries which may be used as a proxy[8]

As a relative catch-22, the IES report commissioned to consider the broader market and social benefits of increased aggregation also notes that approximately $1bn of the $1.8bn in social benefits on an net present value (NPV) basis is comprised of a reduction in costs from a decrease in regulation FCAS enablement volumes. Hence, there is a risk from a market revenue perspective that the IPRR may be a victim of its own success – the more VSR aggregated for dispatch, the less regulation FCAS revenue, the less incentive to continue to operate VSR in dispatch mode.

This relative uncertainty in market revenues supports the call for a strong incentive program.

[8] qed-q2-2024.pdf (aemo.com.au)

Dispatch Mode

The CEC is broadly supportive of the proposed approach regarding dispatch and allowing flexibility through creating hibernation modes. The CEC response to the AEMO HLIA which provides more detail on these points is attached, and a summary of the key points made is below.

Zones

In respect of defining zones, the CEC made the following comments to AEMO in response to the HLIA.

The definition of a zone is likely to be one of the more critical elements of the IPRR design and implementation. The CEC encourages AEMO to consider the largest possible region that would be acceptable to be considered as a zone. The current state based DUID registration approach for VPPs has worked effectively and should be considered by AEMO as the starting point.

Limiting zones geographically will create the following risks:

- If the zones are too geographically limited, it will make it more challenging to meet the proposed 5MW minimum bid size for scheduled dispatch.
- Even with state-based boundaries there are only a handful of VPPs currently registered with AEMO for FCAS that have more than 5MW within their portfolio – the majority of these being Demand Response Service Providers (DRSPs) who would be ineligible under the current interpretation of the proposed Rule.
- Even if AEMO were to start with a minimum 1MW bid threshold for portfolio registration (rather than 5MW), this will still require 100 – 200+ households within a zone registering their 5 – 10kW CER assets with a market participant. Accounting for market competition, and a percentage of customer who will be uninterested in having their assets scheduled, smaller zones will limit the success of the market change.
- It will make the registration process and management of DUIDs more administratively burdensome, where market participants will need to register and manage potentially multiple DUIDs and portfolios within a single state.
- Managing multiple DUIDs and portfolios within a single state will also add cost. Both directly in initial registration, and adding new capacity, but also internal business costs in managing multiple portfolios.
- It will also make tendering more complex if market participants are required to submit tenders for each zone they are operational in. AEMO has noted some alternative incentive structures (discussed in more detail below) which would also be more complex if there was a granular zone breakdown. The CIS tenders, for instance, have been designed around state auctions. If this was to move to zonal auctions for VSRPs this would a departure.

AEMO trial

As noted above, the range of technical and implementation challenges are likely only going, to be realized at the point that AEMO starts the design work and out of market testing for market participants.

For this reason, we support the AEMO suggestion of a longer testing window with a start-date delayed until Q1 2027 to ensure that the majority of these issues are resolved before VSRs are officially scheduled for dispatch.

In respect of sequencing, we also believe that it will be important that incentives are made available ahead of the trial starting with AEMO. Market participants will incur set-up costs, and consumers will expect incentives for their system used in dispatch even under a trial scenario. A successful incentive program, deployed early, will likely result in the largest number of participants in the trial, which in turn, will deliver the best outcomes for AEMO from a design and implementation perspective.

Additional Technical Points

Flexible export platform/ Distribution network limits may impact participation

The AEMC Draft Determination acknowledges there is a risk of distribution network limits impacting on market participation, and the CEC agrees.

The disparate approach taken by regions and distribution businesses in introducing their own platforms may make it challenging for market participants to coordinate signals across multiple platforms when forming bids. Further, there is no clarity or agreed upon approach for how flexible exports will be deployed. If sent in real time, it will need to be perfectly coordinated to enable appropriate bidding and rebidding behaviour from market participants. If flexible exports are enabled through different methods (i.e. real-time versus day-ahead limits), then there is also a risk that some jurisdictions may be easier for market participants to participate in dispatch mode than others.

The viability of the Dispatch Mechanism will also be impacted by other network service provider (NSP) controls like emergency backstop mechanism. For instance, the approach of using a third-party Generation Signalling Device (GSD) might make it more challenging for market participants to use those CER given the potential non-compliance risks and lack of visibility that market participants will have over their VSR portfolio. These kinds of requirements should be factored into the AEMO document design, with consideration given to the exemptions that exist from non-compliance action were VSRs do not follow dispatch instructions due to AEMO or network interventions.