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Ben Davis
Director
AEMC

Submitted via AEMC website

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Dear Ben

RE: Integrating price-responsive resources into the NEM – consultation paper

Thank you for the opportunity to provide feedback on the *Integrating price-responsive resources into the NEM* consultation paper.

Enel X operates Australia's largest virtual power plant.[1] We work with commercial and industrial energy users to develop demand-side flexibility and offer it into the National Electricity Market's energy and ancillary services markets, the reliability and emergency reserve trader mechanism, and to network businesses.

This submission sets out our feedback on the consultation paper. The key points are:

- We consider the costs of this rule change are likely to outweigh any benefits. The incentives to participate in the proposed mechanism are low, particularly where traders can already access markets without onerous compliance obligations. As such, it is unlikely that any benefits of introducing Scheduled Lite will be realised in practice.
- Visibility mode, in particular, appears to have very few benefits compared to the costs of implementation and participation. Even if traders choose to participate, we understand that AEMO would not use the submitted information to inform dispatch, on the basis that it cannot be relied upon. This approach eliminates any potential benefits associated with incorporating more accurate load forecasts into the dispatch mechanism.
- Instead of introducing a costly new framework that is unlikely to be used, we consider the AEMC and AEMO should focus on:
  - Clearly defining the problem, which is currently not well articulated
  - Considering less heavy-handed approaches to address the identified problem(s)
  - Expanding participation in existing mechanisms that provide AEMO with visibility and control of price-responsive demand, including by reducing barriers to participating in the Wholesale Demand Response Mechanism.

We look forward to working with the AEMC on these issues. If you have any questions or would like to discuss this submission further, please do not hesitate to contact me.

Regards

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[1] Per AEMO Registrations

The case for change

Enel X considers that the case for change has not been made to introduce Scheduled Lite. Overall, we consider that the problem has not be well defined, the proposed solution is onerous, and the identified benefits are unlikely to be realised. By more clearly defining the problem, incremental solutions that better target AEMO's concerns in a lower cost way could be identified.

The two proposed elements of Scheduled Lite appear to be targeting two separate issues:

1. Visibility mode appears to be intended to provide AEMO with greater visibility of how price responsive assets are being used, in order to improve AEMO's forecasting. Encouraging market participants to submit demand bids seems to be an extreme way to improve forecasting techniques. As discussed further below, there may be incremental changes that could be made to improve AEMO's access to information about price responsive resources.

2. Dispatch mode appears to be intended to encourage greater participation by price responsive resources in the energy market. As discussed further below, we consider a better way to do this is to improve existing mechanisms for accessing energy markets.

We understand that increasing penetration of price-responsive resources in the system is making the market operator's job more difficult. However, a core part of AEMO's role has always been to make forecasts and decisions under uncertainty.

AEMO's job may be more straightforward if it shifts the forecasting risk onto retailers, aggregators and customers by encouraging – or requiring – price-responsive resources to become scheduled. However this imposes significant costs and risks on market participants, even in a "lite" version. Particularly, under visibility mode, where AEMO does not propose to incorporate indicative bids into dispatch, it is not clear that the overall costs to customers would be any lower than under existing arrangements where AEMO manages uncertainty through FCAS and, if necessary, the RERT mechanism.

Rather, we consider AEMO and the AEMC should first explore lower cost, incremental approaches to improving existing options for load to be more visible and controllable, including through changes to the DSP information obligations, and the Wholesale Demand Response Mechanism (WDRM). The WDRM was specifically designed in recognition that it is difficult to accurately predict an individual customer's demand minute-to-minute, but much simpler to determine its capability for demand response. The mechanism provides a means to allow customers to provide – and, importantly, be rewarded for – demand response.

Improving demand forecasting (visibility mode)

The purpose of visibility mode appears to be to provide AEMO with access to more information about how price responsive resources are being used, in order to help improve its demand forecasting. AEMO does not intend to rely on the information to inform dispatch, and so the usefulness of this information is limited to improving forecasting over longer timeframes.

While the benefits are limited, the costs for traders to participate are high. We agree with AEMO's view that participants would need an incentive to opt into visibility mode. However, we do not agree that the incentives proposed by AEMO are likely to be sufficient to encourage participation. The incentives suggested by AEMO, and Enel X's response, are set out in the table below. In addition, we agree with the disadvantages set out by the AEMC in Table 3.1 of the consultation paper.

It is difficult to comment with certainty whether traders would be incentivised to participate in visibility mode without having a better understanding of the likely level of any incentive payments, or relief from cost recovery payments. However, these benefits would have to be reasonably high to encourage participation, and ultimately end users would need to foot the bill.

Suggested incentive	Enel X response
Pre-dispatch schedule provided to participants	It is not clear why this would incentivise participation. Existing market participants already receive this information, so any incentive this provided would be limited to a small pool of potential Scheduled Lite participants.
Reduced cost recovery for participants for: 1. Market ancillary service 2. NSCAS and system restart 3. Interventions	The value of this incentive will depend on how much the participant currently pays for these services – that is, the value of reducing cost recovery for these services will be low if these costs are already small. Further, as noted by the AEMC, reducing cost recovery for these services from those participating in visibility mode will simply increase costs for others. Unless visibility mode actually reduces the need for these services, we do not consider this approach appropriate.
Payment (e.g. through tender process in specific regions and time periods)	Becoming "visible" will mean incurring some reasonably significant fixed costs, as well as ongoing costs. Unless the payments are guaranteed to allow cost recovery for these costs, it is difficult to see a business case to participate. However, any payment for visibility mode would presumably need to be recovered from other market participants, and ultimately customers. Unless participating in visibility mode significantly reduces market costs (e.g. AEMO's costs or the spot price), this approach appears to simply impose additional costs on consumers. Further, if the value of visibility to AEMO is limited to certain time periods, visibility mode may be an expensive solution for a problem that doesn't arise very often. By clearly defining the periods or types of periods that AEMO would benefit from additional information, alternative, lower-cost solutions may be able to be identified.
Link eligibility to provide contingency FCAS to participation in Scheduled Lite	Unless visibility is required for the provision of FCAS (which it hasn't been to date) then it would be poor regulatory practice to try to address visibility via a new obligation on a sub-set of participants in market that already operates effectively. The approach would discriminate in favour of scheduled resources and reduce competition in FCAS

	markets. This moves away from the voluntary intention of the mechanism.

The AEMC has also considered making participation mandatory. We agree with the AEMC's concerns it would be difficult to mandate participation in visibility mode. In addition to concerns about being able to identify resources and monitor participation, the AEMC would need to introduce penalties for non-compliance/non-performance to encourage participants to submit accurate information. However, there is a risk that this would simply discourage customers from utilising their price responsive resources. This would not be consistent with minimising the costs associated with a shift to net zero and higher penetration of variable renewable energy, where price-responsive resources have a valuable role to play.

Further, making participation mandatory does not address the underlying problem – that AEMO considers it is cannot rely on the information. Consequently, AEMO would receive significant quantities of information that cannot be used effectively, while imposing high costs on those that are forced to participate.

It is not clear from AEMO's rule change request whether they have considered alternative, lower-cost approaches to improving their forecasting when it comes to price-responsive resources. For example, the information required to be submitted to the Demand Side Participation Information Portal could be refreshed and its use potentially enhanced. We note that AEMO is currently reviewing its DSP Information Guidelines and recommend that its review be considered in this light.

Similarly, we note that AEMO is currently reviewing its DSP Forecasting Methodology. Again, we see this as an opportunity for AEMO to consider alternative models of demand side behaviour, including approaches used in other markets.

Dispatch mode

The purpose of dispatch mode appears to be to encourage price responsive resources to participate directly in energy markets. This is a different objective to visibility mode: rather than simply accessing greater information, AEMO appears to be seeking to activate greater demand side participation to assist during critical grid events.

We do not consider dispatch mode would deliver on this objective. This is because either: (1) traders can already access the identified benefits without having to be scheduled (in some cases by design); or (2) in the case of load, it's difficult to accurately predict an individual customer's demand minute-to-minute.

We agree with the costs of implementing dispatch mode identified by AEMO, including the cost of installing operating and monitoring systems, and compliance costs.

On the flipside, there are very limited incentives to participate. As identified by the AEMC, it seems likely that the magnitude of benefits available to retailers as well as other traders (including SGAs and aggregators) from existing arrangements are sufficiently high, without the added compliance costs, dissuading participation in dispatch mode.

The table below sets out the benefits identified by AEMO to participating in dispatch mode, along with Enel X's response.

Suggested incentive	Enel X response
The ability to schedule resources	It is not clear what the benefit is here. SGAs and aggregators can already access the wholesale market if their resource is spot exposed or participating in WDRM - so there is no particular benefit in being scheduled.
The ability to co-optimise energy and FCAS	It's not clear what the benefit is here, particularly where traders already have access to both the wholesale and FCAS markets.
The eligibility to provide regulation FCAS	Our understanding is that the barriers to non-scheduled resources providing regulating FCAS are more than just regulatory – there are technical challenges to be addressed, too. It would be helpful if the AEMO/AEMC could provide further detail on how this might work, what changes to the regulating FCAS requirements might need to be made, and the potential costs of dispatch mode providers complying with the requirements to provide regulating FCAS.
The ability to access other services such as operating reserves, capacity certificates or primary frequency response	Our understanding is that the operating reserves market is unlikely to be implemented, and similarly the approach to a capacity mechanism has shifted substantially from when Scheduled Lite was first contemplated. Further, demand response is not able to provide PFR (although we note batteries could). Again, there appear to be very few benefits here, particularly for flexible load resources.
Ability to set the spot price	Being able to set the spot price is not a strong incentive for participation. The AEMC notes this was the main benefit identified in New Zealand for participating in a similar mechanism. However, our understanding is that there has been no/ low uptake in that scheme.

In Enel X's experience, demand bidding approaches have failed to see any meaningful uptake in other markets. This is because participating customers must be spot-exposed and have the sophistication and stability of operations to accurately forecast and hedge their load. As a result, demand bidding approaches are only suitable for customers whose demand is very predictable and whose sophistication and risk tolerance is such that they are willing to take on spot price exposure and engage in derivative trading. This does not work for the vast majority of C&I loads, or smaller customers. This is why there are very few scheduled loads in the NEM, and why demand bidding mechanisms in other markets have seen no uptake (e.g. New Zealand).

Instead, the more effective way to bring demand flexibility into the wholesale market, and where other markets have seen more success, is to separate load flexibility from retail and allow third parties to sell demand reductions (or "negawatts") directly to the wholesale market. This is what the WDRM delivers. Separating load flexibility from retail means consumers can remain on the fixed price variable volume contracts that they prefer, but also access the value associated with the portion of their load that is flexible and provide that flexibility to the market when the grid values it..

The AEMC raises the question of whether participation should be compulsory. In response, Enel X notes that:

- The SGA framework was specifically designed to allow small generators to participate in the wholesale market without the associated costs of being scheduled. Participating in dispatch mode would introduce new costs compared to operating as an SGA today. Ultimately, there is a risk that customers would choose to withdraw their resources from the market altogether if the costs of participating are considered too high.
- As above, the WDRM was designed to enable demand flexibility to be offered into the market when the grid needs it (as incentivised by high spot price in tight demand/supply periods) without having to submit consumption bids. As for SGAs, if WDR loads are forced to participate via Schedule Lite, they may prefer to simply withdraw from the market.

The success of dispatch mode relies on customers and traders choosing to participate, and it's not clear the incentives to do so are sufficient. The benefits are small, participation in the wholesale market is already possible, and it would be more costly for resources to participate under dispatch mode since they would have to comply with dispatch instructions or face penalties for not doing so.

Enel X considers a better way to encourage greater participation by price-responsive load is to improve existing mechanisms, particularly the WDRM. The WDRM was specifically designed to make it easier for demand flexibility assets to participate in the wholesale market without requiring consumption bids for their whole load. WDRM also supports the provision of demand flexibility via on-site generation and BESS.

There are a range of ways in which the WDRM could be improved to maximise participation by C&I energy users:

1. **Amend the NER to enable sites with multiple connection points to participate in the WDRM.** Sites that have multiple, electrically-connected connection points are not eligible to participate in WDRM. Enel X has submitted a rule change to the AEMC to remove this restriction. Many large energy users have sites with multiple, electrically connected connection points. These sites are currently not eligible to participate in WDRM but, if the rule change was made, would bring significant MW of visible, flexible capacity into the market. See our rule change request for further details on this issue.

2. **Review the WDRM baseline eligibility thresholds**. In its final determination on the WDRM baseline eligibility policy, AEMO said that it would review the baseline eligibility thresholds (RRMSE and ARE) annually, starting in 2022, to "ensure that [they do] not unnecessarily restrict WDRM participation", and that it would consult publicly when it does. No such public review has been conducted to date. Two years on from WDRM start, it makes sense to review whether these thresholds are appropriate, and to do so through an open and consultative public process.

3. **Implement changes to allow sites with solar, and portions of variable load, to participate in the WDRM.** Sites with solar, or that have portions of load that are highly variable, do not meet the probability of load requirements to be eligible to participate in the WDRM. This issue could be addressed through providing flexibility in the location of WDR response, and associated metering, such as that being contemplated through the FTAs rule change. See our submission to the *Unlocking CER Benefits through Flexible Trading* Directions Paper for our proposed solution to this issue.

4. Review the threshold for DNSP endorsement of aggregations (currently 5 MW). There is no real basis for this threshold and the endorsement process is complex to navigate. Unfortunately, the endorsement framework only serves to disincentivise aggregation and reduce incentives to participate in the WDRM.

The benefits of improving WDRM will expand as more players seek to enter this market. Various other policy initiatives have increased the incentive to participate in the WDRM, for example:

- The NSW Government has made participation in the WDRM a prerequisite for demand response to provide reliability services for its firming tenders.
- Access to the demand response component of the NSW Peak Demand Reduction Scheme requires WDRM participation.
- The NSW Government has accepted a recommendation for its agencies with large electricity loads to investigate participating in the WDRM themselves.[2]
- Demand response resources will be required to be scheduled through the WDRM in order to participate in Capacity investment scheme tenders.

As a result of these policy initiatives, interest in participating in the WDRM will grow.

In Enel X's view, the AEMC and AEMO's time would be better spent improving the WDRM framework to catalyse the success of the above initiatives, rather than imposing significant costs on consumers for the questionable benefit of the scheduled lite proposal.

[2] NSW Government, Office of Energy and Climate Change, Electricity Supply and Reliability Check Up – NSW Government response, September 2023, p. 14.