15 September 2023

Ms Anna Collyer
Chair
Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

Project Reference Code: ERC0352 and RRC0051

Dear Ms Collyer

Integrating price-responsive resources into the NEM

Energy Queensland Limited (Energy Queensland) welcomes the opportunity to provide comment to the Australian Energy Market Commission (AEMC) in response to its consultation paper on *Integrating price-responsive resources into the NEM* (the Paper).

This submission is provided by Energy Queensland, on behalf of its related entities, including:

- Distribution network service providers, Energex Limited (Energex) and Ergon Energy Corporation Limited (Ergon Energy);
- Retailer, Ergon Energy Queensland Pty Ltd (Ergon Energy Retail); and
- Affiliated contestable business, Yurika Pty Ltd and its subsidiaries, including Yurika Metering.

Energy Queensland's comments on the proposed amendments are included in the attached.

Should the AEMC require additional information or wish to discuss any aspect of this response, please contact me on 0429 394 855 or Laura Males on 0429 954 346.

Yours sincerely,

Alena Chrismas

Alena Chrismas
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Encl: *Energy Queensland comments to the consultation questions.*

AEMC Question	Energy Queensland response
QUESTION 1: DO YOU AGREE THAT PRICE-RESPONSIVE RESOURCES NEED TO BE INTEGRATED INTO THE NEM?	
1. The Commission has identified five types of issues with increasing volumes of price responsive resources. Do you agree with this breakdown of the issues? What do you consider the magnitude of each issue is? How is this likely to change over time?	While Energy Queensland agrees with the identified issues of increasing volumes of price responsive resources, it is not clear how a voluntary program targeting distributed energy resources[1] (DER) would provide an effective and efficient solution to the challenges as outlined in the Paper. We suggest visibility of behind the meter DER could improve the accuracy of the forecasts for the Australian Energy Market Operator (AEMO), but it remains unclear how it addresses network operational issues such as minimum demand. Of primary concern to distribution network service providers (DNSPs) is the network impact of such resources, which may or may not align with market signals. Ergon Energy and Energex have been utilising load control of hot water and air-conditioning systems for many years[2] and have found this has assisted in managing the demand from such devices. The emergence of behind the meter storage and electric vehicle chargers provide similar challenges. To further address this issue, Ergon Energy and Energex have developed dynamic connections contracts. These enable customers to maximise the utilisation of their DER through communicating dynamic operating envelopes (DOE) within the local constraints of the network. This technology could also be leveraged to provide aggregate visibility of DER flexibility or incorporate transmission or system level constraints. It is unclear how scheduled lite improves the accuracy of the DOE calculation. A large fleet of DER responding to a market signal is not guaranteed to be always aligned with the local network hosting capacity. Moreover, a unique feature of the energy transition in Australia is the volume of DER connected to the distribution network. Hence, if the goal is to reduce the overall electricity cost for all customers, it is important to seriously consider a more decentralised model for operating the future grid with high volumes of decentralised price

[1] The current National Electricity Rules, relevant Guidelines and standards refer to distributed energy resources (DER), we therefore use this terminology throughout this response, rather than consumer energy resources (CER).
[2] https://www.energex.com.au/__data/assets/pdf_file/0012/1000452/2022-23-Demand-Management-Plan.pdf

	responsive resources as an alternative to centrally managed/dispatched models inspired by the current wholesale energy market. Energy Queensland also highlights possible limitations of the proposed FTM2 model. Any benefits of the visibility of price responsive resources may be undermined in this scenario as customers can participate as part of a virtual power plant (VPP) arrangement as a price responsive resource. They can also switch back to their normal connection and use the DER within their own installation. For this reason, the FTM2 model may continue to negatively impact network constraints. A further challenge warranting consideration is the cost of potential multiple technologies. Having data flows visible through different mechanisms to market settlement may result in multiple telecommunications being installed on the same equipment, each servicing a slightly different purpose and increasing costs for participants.
QUESTION 2: REPRESENTING PRICE-RESPONSIVE RESOURCES IN SCHEDULING PROCESSES	
1. Is participation in this mechanism dependent on whether price-responsive resources can be separated at or behind the connection point (currently being considered through the "Unlocking CER benefits through flexible trading" rule change)? Please explain what impacts separating CER would have on traders' participation in energy markets.	Energy Queensland suggests that meaningful participation in either of the options proposed in the Paper would require appropriate metering and control. Hence, considering these two rule changes in isolation is not appropriate. In relation to flexible trading arrangements, as per our response to the AEMC's *Unlocking CER Benefits Through Flexible Trading* consultation paper in February 2023[3], we reiterate several issues need to be investigated further, including simplicity for customers, overall cost benefit analysis and subversion of network benefits.

[3] https://www.aemc.gov.au/sites/default/files/2023-03/Rule%20Change%20Submission%20-%20ERC0346%20-%20Energy%20Queensland%20Limited%20-%2020230227.PDF

2. Do you have views on the need to define price-responsive resources or the traders that might coordinate a large amount of such resources?	Energy Queensland strongly suggests that customer protections must form a key component of any market design. As such, consideration must be given to what resources can be controlled in such a manner without impacting customers. Any ambiguity in the definition of price-responsive resources, ability to shift resources and their forms of trading, including the roles and responsibilities could result in suboptimal or even undesired outcomes for customers and additional network impacts. We note that price-responsive resources would be an addition to distributed energy resources and consumer energy resources.
QUESTION 3: VISIBILITY MECHANISM - ENCOURAGEMENT TO PARTICIPATE	
1. What are your views on the incentive mechanisms outlined in Table 3.1?	Energy Queensland provides no comment.
2. Are there any alternative incentives the Commission should consider?	As DER penetrations grow Ergon Energy and Energex expect that customers will increasingly choose Dynamic Connections[4] (or other DNSP equivalents[5]) based on CSIP-AUS (Common Smart Inverter Profile – Australia SA HB 218:2023[6]). This could provide an alternative visibility mechanism for a growing share of customer DER without further incentives.
3. Should mandatory participation in the visibility mode be considered? a. If so, what types of traders/ resources should be required to participate and what criteria (for example size in a region) or circumstances (observed behaviour or performance) could the requirement to participate be based on?	Energy Queensland provides no comment.

[4] https://www.energex.com.au/home/our-services/connections/residential-and-commercial-connections/solar-connections-and-other-technologies/dynamic-connections-for-energy-exports
[5] https://www.sapowernetworks.com.au/industry/flexible-exports/
[6] https://store.standards.org.au/product/sa-hb-218-2023

QUESTION 4: ASSESSMENT OF VISIBILITY MODE	
1. Do you think visibility mode would be effective as designed? If not, what improvements or amendments would you suggest and why?	In Energy Queensland's view, it is unclear how a voluntary visibility scheme could provide a range of benefits and solve the five identified issues. This proposal appears to be designed solely to improve AEMO's forecasting capability. Given improved network visibility is a crucial capability for DNSPs that will evolve with the roll out of smart meters and dynamic operating envelopes, it is important to consider alternative approaches for AEMO to achieve the same outcome through collaboration with DNSPs, so that the improved network visibility at the distribution level could be passed on to AEMO appropriately. This could significantly reduce the investment required for the visibility option. At least for the short to medium term before the volume of behind the meter storage and VPPs increase significantly.
2. Do you agree with the Commission's initial assessment of visibility mode's ability to achieve the outcomes identified?	The Commission's initial assessment appears to be very optimistic and limited in that it only considers the benefits and not the associated costs. We suggest a detailed assessment and performance review of the wholesale demand response program is warranted prior to extending this to residential customers.
3. If we progress with this mode, what should the Commission consider in terms of implementation of this mode?	It is our opinion that an appropriate cost benefit analysis is required.
4. Is visibility mode needed as a stepping stone to the dispatch mode?	Energy Queensland suggests visibility mode is not required as a stepping-stone to dispatch mode. We suggest dispatch mode could be an extension to the wholesale demand response program.
QUESTION 5: DISPATCH MODE — INCENTIVES TO PARTICIPATE	
1. Do you think dispatch mode would be effective as designed? If not what improvements or amendments would you suggest and why?	Energy Queensland provides no comment.
2. What costs would traders incur to participate in dispatch mode?	Energy Queensland provides no comment.

3. Is access to the wholesale electricity market and other markets (for example regulation FCAS and PFR) sufficient incentive to participate in dispatch mode?	Energy Queensland provides no comment.
4. Are there other factors that would encourage or discourage participation in the dispatch mode?	In Energy Queensland's view, network constraints may not be aligned with market constraints. Traders will therefore require visibility and understanding of any network constraints that may exist, particularly where the light scheduling unit is comprised of several aggregated systems, which may incur additional cost or complexity.
5. Should participation in the dispatch mode be required? If so, what types of traders/resources should be required to participate, against what criteria and in what circumstances?	Energy Queensland provides no comment.
QUESTION 6: ASSESSMENT OF DISPATCH MODE	
1. Do you agree with the Commission's initial assessment of the ability of dispatch mode to address the outcomes identified?	Ergon Energy and Energex consider that any network benefits could be overstated, given that market signals may not align with network requirements at all times. For the most efficient operation of networks, the network operator should be able to exercise some control over these participants using DOE.
2. If we progress dispatch mode, what does the Commission need to consider in terms of implementation of this mode?	Energy Queensland provides no comment.
QUESTION 7: OTHER ISSUES RAISED IN RELATION TO THE SCHEDULED LITE MECHANISM	
1. Do you consider that the proposed mechanism (or a similar mechanism) should be introduced through a principles-based framework, with the details considered through AEMO's procedures and guidelines?	Energy Queensland provides no comment.

2. Do you consider that the proposed mechanism (or a similar mechanism) requires changes to the NERR to protect consumers?	Energy Queensland provides no comment.
QUESTION 8: ARE THERE PREFERABLE ALTERNATIVE ARRANGEMENTS?	
1. Are there any alternative solutions that you think would be preferable to AEMO's proposal and more aligned with the long-term interests of consumers? What are the costs and benefits of any proposed alternative arrangement?	DOE are being deployed as part of customer offerings such as Dynamic Connections and could be leveraged to provide aggregate visibility of active customer DER flexibility or incorporate transmission or system level constraints. The incorporation of some form of market or price responsive DOE as is already being demonstrated in some ARENA trials[7] could form a more scalable approach. These approaches could be applied regionally when cost benefit is justified. We also suggest, a valid alternative option is to consider decentralised models and system architecture prior to applying a centralised dispatch model to a large number of decentralised behind the meter energy resources.
QUESTION 9: ASSESSMENT FRAMEWORK	
1. Do you agree with the proposed assessment framework? Are there additional principles that the Commission should take into account or principles included here that are not relevant?	In Energy Queensland's view, cost to consumers and consumer protection should be a central consideration. Customers own and use the resources, hence any incentives should be passed on to customer appropriately.
QUESTION 10: VISIBILITY MODEL — PARTICIPATION, DATA AND OPERATIONS	
1. Would traders be readily able to participate and provide the data as proposed? What implementation	Energy Queensland suggests a more thorough consideration of the true cost of procuring and providing detailed data at scale to AEMO.

[7] https://arena.gov.au/projects/sa-power-networks-market-active-solar-trial/

considerations and costs would be required to participate?	
2. Is there anything the Commission could do in designing the rule that would help to minimize the costs and maximise the benefits?	In Energy Queensland's view, greater use of network visibility and orchestration capabilities by DNSPs would assist in minimising costs and maximising benefits. These capabilities are currently premature but are evolving rapidly. Further, the alignment of data requirements with other national electricity market related activities will ensure singular operational platforms/equipment will assist in minimising costs to participants. Energy Queensland recommends further consideration of the way in which low voltage (LV) connected DER participate in the market when there are local constraints. Furthermore, we suggest it is crucial to explore appropriate tariff structures due to the unique challenges associated with wholesale market participation through aggregation across multiple LV network connections.
QUESTION 11: DISPATCH MODEL — PARTICIPATION, DATA AND OPERATIONS	
1. Could price-responsive resources comply with the operational and data requirements? If not: a. How difficult would it be to change your systems to comply with the requirement outlined above? b. Does this depend on what resource is participating?	Energy Queensland provides no comment.
2. Do the proposed compliance arrangements strike an appropriate balance between the reliability of the response and the barrier to participation?	Energy Queensland provides no comment.