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14 September 2023

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

Dear Ms Collyer,

Consultation Paper on Integrating Price-Responsive Resources into the NEM (ERC0352)

SwitchDin welcomes the Australian Energy Market Commission (AEMC) Consultation Paper on the National Electricity Amendment (Integrating Price-Responsive Resources into the NEM) Rule. We are happy to provide some recommendations that we believe will improve customer support and social license.

SwitchDin is an Australian energy software company that bridges the gap between energy companies, equipment manufacturers and energy end users to integrate and manage energy resources on the grid. SwitchDin's technology enables our clients to build and operate vendor-agnostic virtual power plants (VPPs) and microgrids, and to optimise performance across fleets of diverse assets. Founded in 2014, SwitchDin operates in all Australian states, including in leading-edge distributed energy projects like Simply Energy's national VPP, flexible export programs in South Australia (SA) and Victoria, Project Symphony in Western Australia (WA) and the Solar Connect VPP in the Northern Territory (NT). We work with distribution network service providers (DNSPs), electricity retailers, inverter original equipment manufacturers (OEMs) and aggregators to enable and utilise flexible export capability.

We understand that the Australian Energy Market Operator (AEMO) needs more visibility of consumer energy resources (CER). SwitchDin supports this objective.

We recommend the participation incentives for 'visibility mode' should commence with direct payment with the level of payment reducing over time. This would encourage VPP formation and participation in the early stages of the scheme, with incentives tailing off as traders recover costs and become more familiar with the operation of the new mechanism. Participation would also be further encouraged by use of digital, low cost interfaces for registration and portfolio updates.

We do not support the proposed design approach for 'dispatch mode'. The scheme treats price-responsive CER like conventional generators, even though they behave very differently, affecting the way that they can potentially bid and participate in the market.

We are concerned that any mechanism that adds new costs or regulatory obligations to VPPs could set back the prospects for VPPs. At this stage of the development of the VPP market, policy makers should be looking to drive uptake, rather than adding new costs.

The proposed 5 MW registration threshold and 1 MW bidding increments are too high. Large registration thresholds present a significant barrier to entry by new participants. Lowering bidding increments and registration sizes would increase competition, improve scheduling accuracy and reduce the unnecessary waste incurred by large increments. We recommend a registration threshold of around 100 kW, with bidding increments of 100 kW.

Thank you for the opportunity to respond to these important issues. I remain available for further discussions and inputs.

Best regards,

Darren Gladman
Head of Policy and Regulatory Affairs

Responses to questions raised in the Consultation Paper

QUESTION 1: DO YOU AGREE THAT PRICE-RESPONSIVE RESOURCES NEED TO BE INTEGRATED INTO THE NEM?

The Commission had 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? How is this likely to change over time?

We understand that AEMO needs more visibility of CER. SwitchDin supports this objective.

We agree that price-responsive resources need to be integrated into the National Electricity Market (NEM). The breakdown of the issues presented in the AEMC Consultation Paper seems reasonable. We are not able to provide an estimate of the relative magnitude of each issue or the likelihood of that changing over time.

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.*

The 'Schedule Lite' approach largely relies on flexible trading arrangements, or otherwise will require forecasting for the entire site load rather than just the resources under direct control. However, the introduction of flexible trading arrangements would not solve the challenges of implementing the proposed 'dispatch mode'. Challenges with maintaining state of charge (SOC) and the difficulty of predicting the impact of local usage on SOC would remain.

This is a very congested policy space. We urge the AEMC to delay the next stage of the 'Scheduled Lite' consultation until after the publication of the Final Report of the 'Unlocking CER benefits through flexible trading' rule change.

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?*

We agree with the observation in the Consultation Paper that a voluntary mechanism to encourage participation would not create a need to define price-responsive resources or the traders that coordinate them, whereas mandatory arrangements would very likely create a need for definition in the National Electricity Rules (NER).

QUESTION 3: VISIBILITY MECHANISM - ENCOURAGEMENT TO PARTICIPATE

1. *What are your views on the incentive mechanisms outlined in Table 3.1?*

VPPs can currently directly respond to price signals rather than bidding in and being dispatched, so there needs to be something extra to incentivise participation. This is particularly important because there will be costs incurred to participate. We are concerned that any mechanism that adds new costs or regulatory obligations to VPPs could set back the prospects for VPPs. Participation by VPPs in Frequency Control Ancillary Services (FCAS) markets has declined recently. Adding additional hurdles to VPPs could discourage orchestration of CER. At this stage of the development of the VPP market, policy makers should be looking to drive uptake, rather than adding new costs.

We recommend commencing with direct payments as a trial to enable price discovery. Mandatory requirements should not be considered until the Australian VPP sector has recovered from its current downturn.

2. *Are there any alternative incentives the Commission should consider?*

Yes. We recommend the participation incentives should commence with direct payment with the level of payment reducing over time. This would encourage VPP formation and participation in the early stages of the scheme, with incentives tailing off as traders recover costs and become more familiar with the operation of the new mechanism.

Participation would be further encouraged by use of digital, low cost interfaces for registration and portfolio updates. The current registration processes are inefficient and discourage participation. The existing processes will not be fit for purpose if the scale of aggregated CER participation increases.

3. *Should mandatory participation in the visibility mode be considered? If so, what type 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?*

Yes, mandatory participation should be considered. However, the costs should be quantified and carefully considered. Adding significant new costs to VPPs would exacerbate the downturn being experienced by Australia's VPP sector.

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?*

We believe the proposal would be effective, noting the limitations outlined by the Commission. We support the introduction of 'visibility mode'. However the policy implementation should be mindful of creating and sustaining the conditions that encourage customers with CER to participate in VPPs. Without participation in VPPs, CER will remain neither orchestrated nor visible. This would undermine the achievement of the goals of the 'Scheduled Lite' rule change proposal.

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 seems reasonable.

3. *If we progress with this mode, what should the Commission consider in terms of implementation of this mode?*

The Commission should bear in mind that the primary objective for VPP policy should be to encourage further uptake of orchestration. Visibility and dispatch of VPPs is desirable, but not if the policies to achieve that are sufficiently onerous or expensive as to discourage CER customers from joining VPPs. It is better for CER to participate in VPPs under the current policy settings than for CER to remain outside of VPPs under the rules proposed in the 'Scheduled Lite' rule change. The Commission needs to keep in mind the 'bigger picture'. What is the rate of participation in VPPs? Is it increasing or declining? What are the reasons behind the downturn in Australia's VPP sector? How can the 'Scheduled Lite' rule change be implemented at minimal cost while achieving its objectives so as not to discourage VPP participation?

4. *Is visibility mode needed as a stepping stone to the dispatch mode?*

Visibility mode is a logical stepping stone to dispatch mode.

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?*

We do not support the proposed design approach for 'dispatch mode'.

The scheme treats price-responsive resources like conventional generators, even though they behave very differently, affecting the way that they can potentially bid and participate in the market. This may make the 'Scheduled Lite' approach unsuccessful.

Conventional generators are limited by factors such as rated capacity, ramp rate and fuel costs but essentially their bids for a particular interval are largely independent of what they have generated in previous intervals throughout the day. This makes bidding 'relatively' straightforward, particularly where AEMO co-optimises the balance between energy and FCAS. In contrast, batteries are limited by both their rated power and available energy. The energy available in the battery is highly dependent on charging/discharging behaviour in the intervals/hours prior and therefore bidding in availability for the day ahead for all bidding intervals does not make sense as there is no way to describe the energy available. For VPPs that are aggregating thousands of devices, this is confused further as the devices are not exclusively used for energy markets and are primarily servicing local load/generation. It is unlikely to be practical or acceptable to 'lock out' capacity in order to firm up energy/FCAS supply. Even for other price responsive devices (PV limiting, load limiting) there is a time period over which a response can be achieved which is not easily described with conventional bidding processes.

The balance of participating in FCAS and performing energy arbitrage for VPPs is already complicated, despite VPPs being able to be price reactive for arbitrage. Arbitrage affects the ability to provide FCAS both in those active intervals but also the intervals after arbitrage. Bidding ahead for energy arbitrage is likely to further complicate this.

2. *What costs would traders incur to participate in dispatch mode?*

We agree with the Commission's observation that the proposal would increase VPP operating costs and compliance costs.

There is a risk that, as designed, dispatch mode would discourage formation of VPPs. Already, additional costs on VPPs have contributed to a downturn in the sector. We urge the Commission to carefully assess the likely costs of the proposal for VPPs and the very thin margins involved in VPPs, prior to making its decision.

3. *Is access to the wholesale electricity market and other markets (for example regulation FCAS and PFR) sufficient incentive to participate in dispatch mode?*

Participation by VPPs in FCAS markets has suffered a downturn following the introduction of new measurement requirements under the MASS. Making 'dispatch mode' a condition of participation in FCAS markets could simply discourage VPP formation rather than incentivising uptake of dispatch mode.

4. *Are there other factors that would encourage or discourage participation in the dispatch mode?*

VPPs are already facing stiff competition from utility-scale batteries and, to a lesser extent, from neighbourhood-scale batteries. In the face of competition and considering the thin margins involved in the VPP business model, the impact of new regulatory requirements on the VPP business model should be carefully considered.

It is unclear whether the proposed 5 MW minimum threshold to participate in dispatch mode is intended to apply to zonal resources or within the entire NEM region. Regardless of whether they are intended to apply to zones or to the entire NEM, we believe the proposed 5 MW registration threshold and 1 MW bidding increments are too high. Large registration thresholds present a significant barrier to entry by new participants. If the 5 MW threshold is by zone it will be extremely difficult to achieve the required volumes, particularly given that many different retailers or financially responsible market participants (FRMPs) would operate within each zone. A 5 MW threshold could prevent smaller retailers from entering the VPP market.

Lowering bidding increments and registration sizes would increase competition, improve scheduling accuracy and reduce the unnecessary waste incurred by large increments. If the threshold is intended to apply to zonal resources, we recommend a registration threshold of around 100 kW, with bidding increments of 100 kW.

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?*

Participation in dispatch mode should only be required if it can be demonstrated that the additional costs would not significantly damage the VPP business model.

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?*

Yes

2. *If we progress dispatch mode, what does the Commission need to consider in terms of implementation of this mode?*

The Commission should seek to understand the likely costs of the proposal, the margins involved in the VPP business model, the likelihood of the proposal reducing uptake of VPPs and the extent to which VPP uptake might be reduced as a result.

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?*

As a general rule, it would be preferable for the mechanism (or a similar mechanism) to be assessed by an organisation like the AEMC, which has the economic and regulatory expertise to undertake cost-benefit analysis and regulatory impact assessment.

2. *Do you consider that the proposed mechanism (or a similar mechanism) requires changes to the NERR to protect consumers?*

Yes, subject to consultation with consumer representatives.

QUESTION 8: ARE THERE PREFERABLE ALTERNATIVE ARRANGEMENTS?

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 arrangements?

Yes. Alternative designs should be considered that better suit the types of resources available, making it easier to participate and therefore giving AEMO the visibility that they need - for example providing trigger price, flex capacity (MW) and energy (MWh) for price responsive resources over wider time periods.

QUESTION 9: ASSESSMENT FRAMEWORK

Do you agree with the proposed assessment framework? Are there any additional principles that the Commission should take into account or principles here that are not relevant?

In addition to the proposed assessment criteria, we urge the AEMC to consider the likely impact of ‘dispatch mode’ on the VPP business model. It would be counter-productive if the additional costs and complications exacerbate the downturn in Australia’s VPP sector. Owners of CER need to be encouraged into VPP participation. Otherwise, they will continue to invest in CER and it will remain unorchestrated with no visibility.