TESLA

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Australian Energy Market Commission

Submitted via online portal

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North Sydney NSW 2060

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Re: ERC0352 - Integrating Price Responsive Resources into the NEM Consultation Paper – Tesla Response

Dear Rachel

Tesla Motors Australia, Pty Ltd (Tesla) welcomes the opportunity to provide the Australian Energy Market Commission (AEMC) with a response to the Consultation Paper on Integrating Price Responsive Resources in the NEM (the "Consultation Paper").

Tesla is excited by the work being done by the AEMC and AEMO to recognise the potential market value that can be provided by virtual power plants (VPPs) and aggregated small scale assets. Tesla is globally focused on accelerating the deployment of VPPs. We have more than 60,000 customers enrolled in VPPs in multiple markets including California and ERCOT. In Australia we have more than 30MW of capacity across South Australia, NSW and Victoria that is registered in all contingency FCAS markets and actively bidding.

We have been supportive of the work done by AEMO with the earlier VPP Demonstrations trial. We recognise the aspirational targets set by AEMO in the Integrated System Plan (ISP) regarding the percentage of Australia's storage mix that will be provided by orchestrated small-scale assets. However, while the ISP highlights the importance of orchestrated DER as a critical part of the lowest cost Australian energy mix, the reality is that the uptake of customers opting into VPPs has been slower than anticipated. From Tesla's perspective this is due to a number of factors:

1. The majority of small-scale assets in Australia currently are customer owned, hence the change in terminology from distributed energy resources (DER) to consumer energy resources (CER). Customers are more likely to hand over control of their system if the perceived value outweighs the perceived impact on their ability to self-consume and/or access back-up power[1].
2. The customer value proposition that can be offered by retailers and aggregators is primarily tied to market revenues that can be accessed by that VPP and passed back to customers. As noted by the AEMC in the Consultation Paper VPPs currently have access to the following revenue streams:
    a. All contingency FCAS markets
    b. Passive wholesale energy prices – spot market prices at the time of export rather than active wholesale energy market bids.
    c. RERT revenues (note: since these are event-based revenues, these cannot be modelled or factored into any guaranteed customer revenues streams such as fixed monthly credits or up-front product incentives or sign-on payments)

[1] According to the Project Edge customer insights, customers interviewed expect an additional $945 in benefits from participating in a VPP annually, on top of $933 in self-consumption benefits from a battery and $1093 self consumption benefits from rooftop solar panels.

   d. Payment for network services (note: these are ad-hoc, jurisdictional and the distribution networks have been slow to value any service that can be provided by behind the meter assets with recent work primarily focused on dynamic operating envelopes, emergency backstop mechanisms and other control-based, regulated responses).

   VPPs are currently excluded from accessing regulation FCAS market values, participating more directly in energy markets and will be excluded from the new primary frequency response (PFR) payments, all of which are (or may prove to be) valuable additional revenue streams.

3. Market revenues alone may not be enough to drive higher uptake of orchestrated CER. Industry also needs strong supporting policies, and there is a clear lack of policy supporting the update of both behind the meter battery storage (to date one of the main technologies used for residential VPPs) and for VPPs more generally. There has been some state-based support – the South Australian Home Battery Subsidy Scheme (HBS) which was repealed in 2022 being the most successful. Incentives for behind the meter-storage drive the uptake of these assets, and as we saw in South Australia, mandating that assets are “VPP capable” and actively advertising VPPs also resulted in a much higher VPP attachment rate than any other Australian state. A necessary policy change will be an extension of the SRES and a concurrent inclusion of small-scale battery storage systems.

In general, we think that the market reform and policy levers increasingly need to be considered within the same conversation. We are at the pointy end of the energy transition, and we no longer have the time to make sequential change.

We recognise that federal and state policy is far outside the remit of the AEMC, however we it will be important to address both points 2 and 3 above, and we believe market reform and new policy development can be designed in complementary ways. This consultation is a critical first step in achieving comparable market access between VPPs and utility scale assets in Australia, but in our incentive discussion below we discuss how this could also be tied to possible policy reforms.

Tesla believes that VPP technology is capable of providing the majority of the same market services as utility scale assets[2]. We are very supportive of this work progressing. Our general views, comments on both the visibility and dispatch models, and response to AEMC’s specific questions are included below.

General feedback

From an overarching, market-change perspective, Tesla is very supportive of this Rule Change process. We believe it is going to be incredibly valuable in recognising the full suite of services that VPPs can provide to market; improving the revenue stack for retailers and aggregators (traders); and most importantly creating a stronger customer value proposition to drive additional VPP uptake.

We are also generally supportive of the following points included in both the AEMO Rule Change and the Consultation Paper:

- That participation remains voluntary.
- The suggested approach of visibility mode being considered as an entry mode.
    - We are supportive of the two modes operating in parallel with no time or MW trigger being implemented to push participants from visibility mode to dispatchability mode. This provides for more flexibility and optionality for market participants based on their level of market sophistication (and risk appetite) and customer base.

[2] With the exception of services that need to be highly configured for specific locational responses. Participating in a future inertia spot market, for instance, may not be possible if each asset needs to be tuned with a specific inertial constant. This is not to say that VPPs could not provide alternative services – like FFR – that can ease inertial constraints.

  - It would be helpful to understand indicative development timelines and whether the two models are likely to be implemented at the same time, or if this will be staged.

It will also be critical for the AEMC to align on the problem statement that is being resolved by this rule change. From Tesla's read of the Rule Change proposal the main goals seem to be twofold:

1. Provide AEMO with improved visibility of the behaviour of orchestrated behind the meter assets to enable better market planning and reduce over-investment in capacity; and
2. Provide market participants, or traders, with access to markets they have previously been excluded from. This will both improve visibility and create a more efficient market by better utilising CER.

While we may see additional, beneficial outcomes like improving network hosting capacity, from Tesla's perspective this Rule Change should be narrow in focus on the market and market access.

<u>Timing for making the Rule</u>

In the Consultation Paper, the AEMC suggests that the timing for this Rule Change may be extended given the complexity of the subject matter. We agree that the subject matter is incredibly complex, however we do not think an extended Rule Change process is a necessarily a solution.

Tesla views this Rule Change as being quite similar to the Integrating Energy Storage System (IESS) Rule Change, where a significant amount of work will be done in the implementation design. There will be a number of details that will need to be worked out and jointly developed with industry to support implementation following the conclusion of the Rule Change process.

Our concern is that an extended Rule Change process will not necessarily reduce the post Rule Change implementation timelines, which may result in the changes not being recognised until 2027 or later. Again, using the IESS Rule Change as an example, the AEMC initiated the first round of consultation in August 2020 with final market changes being implemented between Jun-24 and Mar-25 – a total 4-5 year process.

Rather than an extended Rule Change process followed by a lengthy AEMO implementation process, we would suggest that the AEMC adopts one of two options to ensure that the Rule Change is implemented as quickly as possible, in a way designed to maximise uptake.

- Option A: Extended AEMC Rule Change Process with AEMO design work done in parallel.
  - This would involve the AEMC running their Rule Change process at the same time that AEMO was engaging in detailed implementation design with likely market participants.
  - We would suggest that this would involve both an AEMC led Technical Working Group, as well as an AEMO led sub-working group specifically focused on implementation.
  - These working groups would input into the Rule Change as it progresses.
  - Under this scenario we would anticipate a reasonably short implementation period following the release of the final Determination and Rule.
- Option B:
  - Existing (or expedited timelines) with a longer AEMO implementation period following the release of the Final Rule.
  - Under this approach we would still suggest their being value in the AEMC setting up a Technical Working Group to support the Rule Change process, however the AEMO implementation working group can occur following the Rule Change finalisation.
  - Also note that under this approach AEMO may need to make minor iterative changes to the Final Rule, similar to iterative changes made to the IESS Rule post finalisation.

With a Rule Change this complex, it will also be important to review industry and AEMO costs and benefits throughout the process to ensure that this Rule Change is adding value.

Zonal registrations

We are supportive of maintaining state DUIDs (or at most zonal registrations driven by DNSP operating zone) – similar to the approach currently taken with FCAS registration. We would not be supportive of anything more granular than that as it will dilute the customer pool, and the rationale for sub-regional DUIDs are not made clear in the Consultation Paper.

It will also be important for market participants to have the option of maintaining more than one DUID per state. This will then allow for different operating modes across different customer types or different technology mixes. For instance, a single market participant might operate a C&I VPP very differently to a residential VPP.

Regarding the 5MW threshold for participating in dispatch, we are indicatively supportive of this. However, we believe that this is something that should be worked out during the implementation design. We would imagine that, similar to historical treatment of utility scale battery energy storage systems (BESS), AEMO will want to retain some flexibility in the short term and will likely prescribe these thresholds through Guidelines, rather than embedding the threshold limit in the NER. This will provide AEMO and industry time to establish whether the limit should be 5MW or lower. So this is not necessarily an element that will need to be embedded in the NER.

Participation from different price responsive assets

The language used by the AEMC in the Consultation Paper regarding participation from different price-responsive assets (section 3.1.3) seems to imply that Traders will only be able to differentiate between flexible and non-flex assets if the Flexible Trading Arrangements (FTA) Rule Change goes ahead.

From Tesla's perspective you should still be able to differentiate between flexible and non-flexible capacity for customers under a standard retail model. The similar model in ERCOT currently allows for either control signals to be sent to specific behind the meter assets (in aggregate) or multiple assets controlled through a single control point. We would expect that AEMO will consider a similar design and implementation approach for the NEM.

We also acknowledge that participating in central dispatch will exclude VPPs from being able to access RERT payments if operating under the Dispatch Model. We assume this is not the case if operating under the Visibility Model – however it would be helpful for the AEMC to clarify this point.

We have separately provided a response to the Flexible Trading Arrangements Rule Change Directions Paper which provides more detail on the current market approach of using CER for different market services. This will hopefully provide some additional clarifying information.

Visibility Model

In general Tesla is supportive of the proposed Visibility Model. Pending more detail on the design, it appears to be a relatively low-effort way for AEMO to gain more insights into how orchestrated behind the meter assets are responding to market signals. We accept all of the benefits that AEMO have put forward, and see the Visibility Mode as primarily a measure to mitigate against future risks; demonstrate further the market value provided by VPPs; and prevent suboptimal Rules being made due to lack of performance data or understanding as to how assets operate. Tesla has previously integrated with AEMO via API to provide real time asset and fleet level data during the VPP Demonstrations Trial. The most challenging aspect was providing accurate forecasts. This will likely need to be the largest priority during the design and implementation phase.

Incentives

We appreciate the breakdown of the different incentive options that the AEMC has provided in Table 3.1. The benefits to date have been a bit unclear, and it would still be helpful for AEMO and the AEMC to consider quantifying examples to show what the incentives might look like (in respect of $/MW or $/asset). Of the five options considered, the direct payment model seems to be the simplest and possibly the most transparent.

We would also welcome AEMO providing more information on the possible incentives under Option 2 regarding reduced costs. We note that for both of these options the negatives noted by the AEMC are around “higher market fees” for market participants not participating in the visibility market. We would imagine that any fee increases would apply to market customers who would have CER in their portfolio and *could* feasible participate under the Visibility Model, so this does not seem too unreasonable.

We are not supportive of Option 5. Mandating participation will be extremely challenging. Noting the AEMC point regarding the challenges on setting threshold requirements, we agree that at the moment retailers effectively have the ability to self-declare that they’re a VPP. We do not see this changing with a mandatory approach, and it will just lead to mixed participation rates and inaccurate datasets.

In respect of Option 4, we also do not think it is appropriate to retrospectively change access requirements for existing markets. Particularly since this will not address any existing issues with contingency FCAS market access, but solves for an entirely different set of issues.

We recognise that both federal and state policy design are clearly outside of the remit of the AEMC, however one other option for incentives would be tying this Visibility Model to access to different policies. If, for instance, the SRES was extended to include batteries, then this might provide an ideal linked policy incentive to drive uptake. This is also likely to be a more generous incentive than the options considered in the Consultation Paper.

Other points

During the implementation phase it will be important to align on the granularity and frequency of data collected and test the scalability of the data ask. Another point in favour of a direct payment is that this could partially offset the cost of data storage.

It will be critical to differentiate whether the data model will be at the aggregate level (DUID or DNSP) or at the device level. Tesla is supportive of providing data in aggregate and has concerns about the scalability of device level data, due to data storage requirements. From a market insights perspective, it also appears the aggregate dataset will be more valuable to AEMO.

We also note that AEMO currently has no visibility of orchestrated CER performance, and would suggest that in the development of the visibility model that we do not let perfect be the enemy of good. For instance, having real time fleet data and hour ahead forecasts is still going to be valuable to AEMO even if providing accurate day ahead forecasts proves challenging.

Dispatch mode

From Tesla’s perspective the benefit of the Dispatch Model is it effectively provides equal access for aggregated small scale assets as currently exists for utility scale assets. We see this as a significant and positive step forward, and an area for Australia to be genuinely world leading.

It will, however, be critical for the design of the Dispatch Model to recognise the unique characteristics of aggregated small-scale CER. Equal market access should not be predicated on compliance with market regulations and systems built for single, large, utility scale assets. All of the market interfaces will need to be developed in a fit-for-purpose manner. AEMO may need to accept that while the market outcomes are the same, the method of interface may look different to traditional utility scale assets.

The latest AEMO Quarterly Energy Dynamics (QED) shows that there is significant value being left on the table for aggregated small scale assets by not being able to access regulation FCAS revenues or participate more actively in energy central dispatch. There is also the additional PFR upside benefit. Outside of the market benefits, there are also policies that explicitly exclude VPP participation due to not being able to participate in central dispatch – this includes both the NSW Firming LTESA and the early proposed design of the federal Capacity Investment Scheme (CIS). We see access to all of these markets as being a significant benefit. The lift in undertaking the work will certainly be high, but the potential market upside is also very high.

Figure 49 Battery revenue dropped from Q2 2022 with reduced energy arbitrage, contingency FCAS remained at similar levels

Quarterly revenue from NEM battery systems by revenue stream

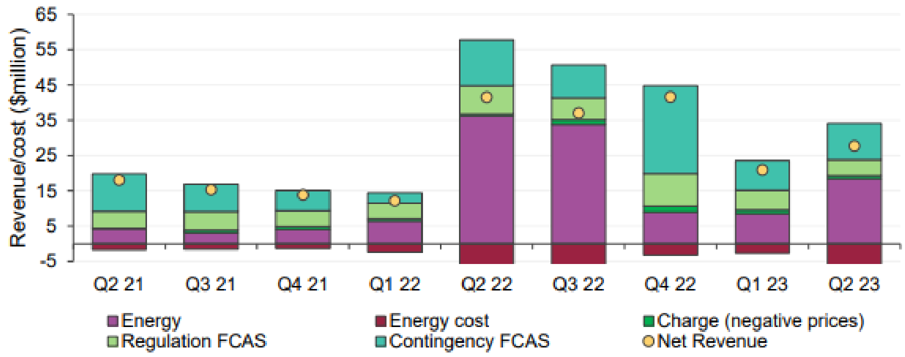

Figure 1: Q2-23 QED[3]

While we recognise that this is outside of the remit of the AEMC, as per comments on the Visibility Model above, we believe that there is an opportunity to explore how this market design could interact with policy levers. Comparing VPPs to utility scale assets, utility scale assets have always had full market access, but merchant revenues alone are not enough initially to drive development. The vast majority of utility scale BESS projects have been supported by either state or federal policies as well as the markets.

One option for the AEMC will be to work through DCCEEW to see how this Rule Change can tie into existing or potential new policies. While we think full market access for VPPs is a step in the right direction, as the AEMC notes the cost may be prohibitive for some market participants, and the cost vs reward may disincentivise others. Looking at opportunities to link dispatchability to enhanced policy opportunities may be an option.

<u>Key elements of Dispatch Mode that will need to be worked out</u>

[3] https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q1-2023-report.pdf?la=en#:~:text=The%20Q1%202023%20maximum%20operational,coverage%20reducing%20distributed%20PV%20output.&text=Average%20coal%2Dfired%20generation%20obtained,the%20same%20quarter%20last%20year.

As noted, the design and development of the Dispatch Mode is by far the most complicated of the two models designed, and there are a lot of open questions regarding how it will work. A non-exhaustive list of open questions we have regarding the structure include:

- Delineation of capacity behind the meter – will the goal be just to bid in controllable or flexible capacity, or is there an AEMO expectation that all capacity will be bid into the system including non-flexible load and generation (the latter being much more complicated)
- Will AEMO use the existing AGC approach, or will it be an AGC-like signal sent via API, building on the design of the Visibility Model.
- Will dispatch signals be sent at a fleet level or to individual assets?
- How will it integrate with dynamic operating envelopes (DOEs) in jurisdictions like South Australia that have already implemented them. Will AEMO adjust their dispatch instructions based on the DNSP DOE? What takes precedence? Will it all be coordinated by a single platform, and if not will the Rule Change mandate to DNSPs that they may need to adjust when and how they send their DOE signals to ensure they do not inadvertently prevent VPPs from being able to participate in dispatch.
- Metering requirements. It will be critical that the costs of any additional metering do not outweigh the benefits gained from the visibility incentives or from participating in the market. We would favour light-touch API based interfaces that utilise existing product hardware as much as possible.
- Interaction with other network schemes such as enhanced overvoltage management will also be necessary to consider.
- Generator performance standards. If assets are effectively scheduled for dispatch will there be an expectation that they need to comply with NER generator performance standards? Or is the existence of AS4777.2:2020 sufficient?

Tesla is happy to support the AEMC and AEMO however we can with the continuation of this Rule Change, including involvement in any Technical Working Group. Please see us as a resource, and if there is any information or further market details not included in our response above, we would be happy to share any additional insights.

Please contact Emma Fagan (efagan@tesla.com) for any questions or follow-up information.

Kind regards

Emma Fagan

Energy Policy and Regulatory Manager

Response to AEMC Questions

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

We accept all of the concerns put forward by AEMO in the Rule Change to the AEMC. We also note the point made by AEMO that duplicating 20% of projected coordinated distributed energy resources with shallow grid-scale storage could result in additional costs of around $1.8bn to 2040. Based on Tesla's analysis, this translates to potential market savings of an approximate $3,000 per 5kW residential system that is integrated into AEMO's systems.

This value needs to be reflected either through the market visibility incentive payments or through linked policy incentives or a combination of both.

Tesla cannot comment on the magnitude of the impacts or the likelihood that these impacts will change over time, as this information sits with AEMO.

QUESTION 2: REPRESENTING PRICE-RESPONSIVE RESOURCES IN SCHEDULING PROCESSES

Is participation dependent on whether price responsive assets can be separated at or behind the meter point (currently being considered through the Flexible Trading Arrangement (FTA) Rule Change?

We are potentially misunderstanding the wording used by the AEMC but this appears to potentially be conflating two separate issues:

- Do we need to be able to differentiate flexible and non-flexible assets behind the meter; and
- Does this need to occur through a separate flexible trading arrangement.

On point one, this should be resolved through the AEMO design and implementation process. Our initial view is that participating in central dispatch will be a far simpler process if only controllable assets participate in central dispatch. Without pre-empting all of the design work, we would consider trying to schedule uncontrolled customer load and/or generation will be nearly impossible.

On point two, separating flexible and non-flexible resources behind the meter is not dependent on the Flexible Trading Arrangements (FTA) Rule Change. This can be simply done through existing retail structures. More information on this point is included in our response to the FTA Directions Paper (which may be read in conjunction with this response).

So in summary it will be important to differentiate different assets behind the meter, however it is not necessary for a third party to do this. It can be done by a Trader (if the FTA Rule Change progresses) but can equally be done by an existing retailer or other market participant.

Do you have views on the need to define price-responsive resources or the traders that might coordinate large amounts of such resources?

If anything, we would suggest that it is better for the AEMC to keep this approach simple. If there is a need for additional definitions in the NER we would broadly these to be grouped along the lines of "small BDU", "small generation" and "small load". We do not see any need to add further definitions of traders. Pending the outcome of the FTA Rule Change this may already create another market classification, but otherwise it will be Integrated Resource Providers or Market Customers providing these market services. Adding new classifications will just add additional and needless complexity.

QUESTION 3: VISIBILITY MECHANISM - ENCOURAGEMENT TO PARTICIPATE

What are you views on the incentive mechanisms outlined in Table 3.1?

Our preferences and views are covered in the content above.

Are there any alternative incentives the Commission should consider?

As covered above, it may be worth AEMO and the AEMC jointly working with DCCEEW to consider the interrelationship between this Rule Change and new policy developments.

Should mandatory participation in the visibility mode be considered?

As per our comments above, we do not believe this is a good idea. It is far too reliant on retailers and traders self-selecting to officially name themselves a VPP or not, and will lead to very poor data.

QUESTION 4: ASSESSMENT OF VISIBILITY MODE

Do you think the visibility mode will be effective as designed?

We believe that increased visibility of orchestrated DER will provide a number of benefits to AEMO which are listed in the Consultation Paper. The true assessment of effectiveness will need to be informed by the ultimate incentive structure that is selected, as well as the more detailed design elements, such as the method for integrating with AEMO, level of data granularity, mode of forecasting etc.

Do you agree with the Commission's initial assessment of visibility mode's ability to achieve the outcomes identified?

Yes

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

What data is collected, how data is collected, modes of forecasting, incentive structures and level of incentive provided, metering requirements etc. As noted above, it's going to be critical that we establish both a Technical Working Group, and ideally an implementation sub-group led by AEMO to work through these requirements.

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

If AEMO establishes an appropriate test environment, there may be some market participants (with over 5MW of existing capacity) that would like to enter straight into the Dispatch Mode. This option should be worked through the Technical Working Group.

QUESTION 5: DISPATCH MODE — INCENTIVES TO PARTICIPATE

Do you think dispatch mode would be effective as designed? If not what improvements or amendments would you suggest and why?

As noted above, Tesla strongly believes that VPPs and orchestrated DER are technically capable of providing all of the same services as utility scale assets, however equal market access will not necessarily look like equivalent processes. For the dispatch mode to be successful, AEMO will need to work with industry to design interfaces which are fit for purpose for aggregated DER. This will include how a single signal can be sent to a fleet to generate a fleet-side response; what data storage requirements will look like; level and granularity of data provided; metering requirements etc.

Another major determining factor in the success of the dispatch mode will be considering generator performance standard requirements. What will the minimum performance standards be for aggregated fleets? How will these interact with AS4777.2:2020 and other small scale asset standards.

An additional piece that will be critical to get right, will be the interaction with DOEs. As has been discussed for many years (since the Open Energy Networks work), if the NSPs are increasingly looking to play a role of distribution system operator (DSO) then we need full alignment with AEMO's market operation role as well. Ideally, we want a single platform that can ingest both DOEs and then send dispatch signals to fleets (to avoid constant real time adjustment by aggregators or fleet operators). A less ideal option would be to have the two separate signals, but ensure they are time synced.

The worst outcome would be if DOEs and dispatch signals are separately sent by AEMO and individual NSPs out of sync in a way that lends itself to non-compliance with one or both. Note that from Tesla's perspective we are not fully convinced that DOEs can be successfully applied to smarter DER operations in a way that is compatible with fleet responses to market signals. Unless DOEs can evolve, and to prevent them being a barrier to DER market participation, they may be considered only as a solution for passive solar.

We are very supportive of this implementation work progressing.

What costs would traders incur to participate in dispatch mode?

This is difficult to fully assess cost impacts until some of the more detailed design elements are established.

Generally we would see costs will fall into the following categories:

Upfront:

- Dedicated engineering work – this will likely include a combination of the following:
    - Potential hardware and software development – depending on current product capabilities.
    - Development of specific interfaces with AEMO; testing and confirmation; developing and/or testing new market bidding functionality
    - System wide modelling or testing – as dictated by AEMO depending on system needs and AEMO expectations (note that we would view the current system modelling and grid connection requirements that apply to utility scale assets being infeasible for aggregated small scale assets to meet).
- Establishing appropriate market functionality. Depending on the approach taken with central dispatch, there may need to be a lot of development for aggregators/ traders looking to participate in dispatch mode. This could include:
    - Work on establishing bidding platforms.
    - Building 24/7 control room functionality (if needed).

Ongoing:

- Resourcing to manage ongoing market participation including 24/7 control room functionality (if needed)
- Data collection and storage.

Tesla has some views on the above, and how to ensure that AEMO establishes appropriate market processes while not being cost prohibitive. As a starting point we recognise that AEMO are predicting potential GW of orchestrated DER capacity. For this reason we acknowledge that there is going to need to be robustness in the treatment of assets that are market participating. There are, however, key differences between VPPs and utility scale assets:

- The size of assets (even with aggregation) is likely to be quite different. We would imagine that most VPPs will be in the order of 5-30MW whereas utility scale assets are increasingly in the 200MW+ category.
- The nameplate capacity of individual assets will likely be very small. While the aggregation of assets will have a market impact, the same transmission challenges presented by individual 200MW assets will not be present for VPPs, regardless of the size.

For all of these reasons above, it will be important for AEMO to take a sensible middle ground. We expect that aggregators and traders will need to show market aptitude and capability, and both individual and fleet assets will need to meet performance standards, however we would not like the bar set so high that it is impossible to meet.

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

As noted we believe full market access is a definite step in the right direction, and we believe it will be a key element of creating compelling customer value propositions and increasing the number of customers that participate in VPPs.

In isolation it may not be enough to fully swing the needle to drive significant market access, so the AEMC should work in collaboration with DCCEEW and state governments to consider links to different policy incentives that can work in tandem with market revenues.

There are a few points associated with relying purely on market revenues to drive the uptake or orchestrated DER:

- Market revenues are inherently uncertain. Unless a market participant also has utility scale assets, they will likely have poor visibility over the level of market revenues that can be earned through active energy and regulation FCAS market access.
- Alternatively aggregators will be reliant on independent market revenue forecasts. In Tesla's experience these can undervalue how responsive rapid-response assets (such as VPPs) actually are, so will be unlikely to provide an accurate view of market revenues. Primary PFR revenues also do not exist yet, so would be considered as pure upside, rather than any kind of bankable revenue stream.
- These points above also impact, in turn, on the customer offering. If aggregators or traders are unclear of the market value associated with these new forms of revenue, then it will be hard to offer customers a firm value – either fixed grid-credits or up-front product discounts. Aggregators or traders are then left with the following choice – either provide a high customer value proposition and risk potentially losing out on market revenues, or creating a fluid customer value proposition that may not be high enough to attract customers.

Linking to policies could provide an element of de-risking these market revenues, and providing transition time for market participants to get comfortable with the market value that may be accessed from participating in the energy and regulation FCAS markets.

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

The use of customer assets following a dispatch signal is likely to be much higher than using assets for contingency FCAS purposes (where they effectively sit as reserve capacity). Warranty and customer impact will need to be taken into account as well. This makes the points above regarding compelling customer value proposition more pertinent.

Should participation in dispatch mode be required?

Definitely not. It will be critical that optionality is built into, and maintained, as a key part of the design.

QUESTION 6: ASSESSMENT OF DISPATCH MODE

Do you agree with the Commission's initial assessment of the ability of dispatch mode to address the outcomes identified?

We agree with the benefits outlined by AEMO.

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

From the outset, we hope the AEMC does progress dispatch mode. It will be an important step in driving full market access for VPPs.

As noted above, implementation is going to be a complex process with lots of development work. Tesla has addressed a number of the things that will need to be considered in respect of implementation in our content above.

QUESTION 7: OTHER ISSUES RAISED IN RELATION TO THE SCHEDULED LITE MECHANISM

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?

It will need to be a combination of changes to the NER and then AEMO Guidelines and procedures that can be more easily amended. For this reason, we think it is important that the AEMC establish a Technical Working Group and/or an implementation working group to work through the long-list of changes that will need to be made and establish the best approach for making those changes.

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

Unclear. If it remains optional it probably won't require NERR changes and should be able to be dealt with through the customer commercial value proposition.

QUESTION 8: ARE THERE PREFERABLE ALTERNATIVE ARRANGEMENTS?

Tesla is supportive of opening up market access for VPPs. We would caution against any alternative arrangements that set up separate markets for VPPs.

QUESTION 9: ASSESSMENT FRAMEWORK

We agree with the assessment framework.

QUESTION 10: VISIBILITY MODEL — PARTICIPATION, DATA AND OPERATIONS

From first principles, Tesla does not see any technical feasibility issues with providing AEMO with increased data to support a visibility model. The level of data that is collected by individual assets is fairly robust, and AEMO has experience with working with industry on a similar initiative through the AEMO VPP Demonstrations Trial.

There is a lot of detail still to be worked out with industry and it will be important to ensure that the data solution is scalable. It is likely that the detail provided in the initial AEMO Rule Change will evolve quite a bit through the design and implementation, so it may be more helpful to withhold initial comments on both the visibility and dispatch model until these details have been discussed in more detail.