Integrating storage – options paper: stakeholder feedback template

The template below has been developed to assist stakeholders in providing their feedback on the questions posed in this paper and any other issues that they would like to provide feedback on. The AEMC encourages stakeholders to use this template to assist it to consider the views expressed by stakeholders on each issue. Stakeholders should not feel obliged to answer each question, but rather address those issues of particular interest or concern. Further context for the questions can be found in the consultation paper.

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Questions		Feedback
Chapter 1 – Registration and participation framework		
Question 1: Registration and classification (p. 17)		
1	Is introducing a new participant category, an Integrated Resource Provider (option 4), to better facilitate entry and participation of storage and hybrid facility, more preferable than modifying existing participant categories (option 3)? Are either option 3 or 4 more preferable to options 1 and 2?	Tesla supports AEMO continuing to explore and address barriers relating to hybrid registrations at the utility scale, and providing small-scale residential and commercial customers with the option of more than one trading relationship per site (noting this should be done through a single connection point). At utility-scale, it remains unclear what rationale AEMC has used in its classification treatment for hybrid facilities under Option 3 and 4. Retaining optionality and ideally expanding flexibility for participants will be critical (see comments on Q4). Of the four options considered by the AEMC – none would be fit for purpose for DER. We need services measured at the inverter terminal, not the connection point (i.e. option 3 would not work in practice), clause 2.2.1 also implies that MSGAs would be scheduled which is a change (see comments on scheduling below). Options 1 is irrelevant for DER, Option 2 still needs additional clarification to properly integrate DER. And Option 4's registration

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		requirements have massive implications for the integration and operation of DER and VPPs (per comments below). A significant risk with Option 4 is what appears to be an approach to mandate all aggregated portfolios into dispatch as scheduled assets. This has huge implications for DER uptake and impacting the customer value proposition directly. Operationally, work has not been done to consider the details and flow-on impacts of this change. For example, for aggregators to be included in dispatch: - What would be the minimum level of control required? What about proportion of load that is not controllable (and hence un-schedulable) - How would AEMO dispatch across portfolios of small-scale assets? - How could improved forecasting capability be used as an alternative to current scheduled dispatch methods? (see AEMO VPP knowledge sharing reports for additional data) - What additional costs/requirements would need to be introduced at site-level? Tesla considers before Option 4 is progressed, more work needs to be done to address these threshold questions, ensuring that DER integration is considered differently to stand-alone utility assets and is not forced into exiting frameworks that do not adequately fit. One approach could see AEMC progress solutions for utility-scale assets ahead of DER requirements. For example, we are supportive of the 'Scheduled lite' concept being further explored in the P2025 work program as a potential new way to approach this with fewer obligations for DER than the current scheduled category entails. Alignment with this rule change and the ESB's P2025 two-sided market work is welcome, however given that both processes have/continue to run in parallel, it continues to be challenging to provide instructive feedback on the interactions between them.
Question 2: Classifying MSGAs (p. 18)		
1	Do you agree that, if an Integrated Resource Provider category (option 4) is established, battery aggregators should use that category and MSGAs should not be allowed to classify storage units exempt from the requirements to	From first principles, AEMC should be seeking to remove barriers to participation of small-scale assets, whether as individual behind the meter assets, or aggregated assets as part of a VPP. We believe that it is important that the MSGA category adequately captures all technology types

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	register as a Generator? And in that case, should the current arrangements regarding the provision of market ancillary services by MSGAs be maintained?	and adequately enables the MSGA to participate in all markets – subject to meeting relevant technical requirements. So it is particularly important that MSGAs are able to provide FCAS. Amending the MSGA category to enable MSGAs to participate in the FCAS markets will be an important step forward (aligning with the aims of the ESB's 2SM work program), and will better enable aggregation of mid-sized assets such as community storage assets. However, we do not believe that any moves should be made to schedule aggregated DER (small or mid-size) until more work is done through the ESB process. We also believe that it is critical that the MSGA mechanism does not become the default position for aggregation of assets. There are many varied customer demographics and participants that will participate under aggregation programs, and while Tesla is supportive of expanding the MSGA classification to include the provision of FCAS, we do not think that the MSGA classification will be broadly used for the aggregation of behind-the-meter distributed energy resources (DER). In particular, we do not think that requiring the development of a separate connection point is a feasible option for most residential customers due to additional costs, complexity and future proofing of sites. We believe that there are a number of quick wins that the AEMC can make to address outdated regulatory barriers for a number of different aggregate customer types. These are outlined below. **1. Community storage assets** At the moment a market gap exists in that battery storage assets <5MW and installed behind a single connection point, cannot provide FCAS unless they register as individual assets. This adds additional cost and complexity to the registration process. In addition, it means that assets that are <1MW will never be able to participate in the FCAS markets as they will not be able to meet the minimum 1MW bid requirements. Allowing aggregation of individual connection points for the purposes of providing FCAS recognises that there is a gap that needs to be addressed, and that these assets are capable of providing a quality FCAS response. It also ensures that

		assets that are technically capable of delivering a service are not locked out of individual markets because of historical regulatory reasons. **2. Residential/ C&I VPPs – DER installed behind the customer connection point** The continued ability of aggregated DER to provide FCAS will be highly dependent on a favourable outcome of the current MASS review process which is being undertaken by AEMO. Finalising the MASS review to codify the VPP trial arrangements is an immediate priority that will ensure a seamless transition from trial arrangements to business as usual settings for VPPs. The MASS review work should ensure that output is measured at the device terminal not at the site connection point. This is the proposed approach for aggregating of DER under the MASS consultation process that AEMO is currently working through. Any market changes need to be consistent with this principle. In respect of the future of aggregation of behind the meter systems we believe the following focus areas need to be a priority: ▪ Design scheduling and forecasting requirements for aggregated DER. Structure requirements around energy market participation in particular. Tesla supports a "scheduling-lite" approach in principle, but the key will be in the detail and there are a number of areas that still need to be worked through. Tesla recommends that consideration is given to the outcomes of the AEMO VPP Demonstrations trials in developing what a scheduling-lite approach looks like. We also suggest that any 'scheduled-lite' approach is trialed ahead of it being introduced – this will also allow more alignment with learnings from AEMO VPP trials. ▪ Explore how forecasting requirement will be designed and how they interact with the scheduling requirements. The VPP trial has demonstrated how hard it is to forecast the performance of any storage asset 8 hours ahead of time. ▪ For most residential customers and behind-the-meter DER, a single connection point will be the preferred approach to create an aggregation framework that is scalable across a range of customer demographics. The costs of establishing a second connection point vary and can be significant where re-trenching or other site development work is needed. **3. Residential/ C&I DER installed behind a separate connection point**

		While we note that in most instances a second connection point will not be the preferred approach for most residential customers, we think that flexibility is going to be needed to allow for more innovative aggregation models and customer retail offers. As more customers are interested in installing DER and participating in VPPs, retailers and aggregators are likely to offer new customer arrangements. As an example, a retailer may own a number of residential solar and storage systems across rental properties for use within the electricity market. If a customer churns away from their retailer, or a new tenant moves in, then the retailer should have the option of transitioning these assets to a separate connection point and continuing to operate those systems under their existing market ID. In this instance this would allow those assets to be managed within a broader portfolio, and would be a far more preferable outcome than requiring the retailer to register as an SGA to operate those assets. <u>Short-term recommendation:</u> AEMO has already accepted that DER registered as ancillary services load at a load connection point can operate effectively as generation as well (effectively codifying the bi-directional capabilities of residential batteries). This position is outlined in the AEMO "Interim arrangements for FCAS". We believe that this approach should be expanded to include DER installed behind a separate connection point. As the AEMC Options Paper is currently exploring options that go beyond the scope of the original rule change proposal, we believe it is also valuable to expand the current accepted treatment of DER installed behind a customer connection point, to also capture equivalent DER installed behind a separate connection point at the same property. **Additional clarifications** Some further clarification would be helpful for how aggregation is treated – ▪ What are the market changes associated with clarifying that MSGAs can aggregate small storage units? Is this clearing up a definitional issue in that the "small generating units" definition does not currently capture small scale storage, and would allow aggregate storage + renewable capacity to be registered (i.e. a connection point with 1MW solar + 1MW storage would be able to register as 2MW).

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Question 3: Existing storage participants (p. 19)		
1	Should existing storage participants be transitioned to a single participant category (as they are currently registered as both a Market Generator and Market Customer)?	As above, provided the new category establishes a better and more streamlined process for registration/classification, the existing framework arrangements would be expected to become redundant over time. If new categories introduce new barriers / remove flexibility and functionality that is currently provided (e.g. 20 Price bands being reduced to 10), then existing registration categories should be granted opt-in grandfathering arrangements for the lifetime of existing assets. Providing flexibility for different commercial models and asset configurations will be key to an effective registration and classification regime. There should not be any unnecessary cost or resource requirements for existing systems or penalties for first-movers deploying storage in the NEM.
Question 4: Scheduling of hybrid facilities (p. 20)		
1	What proportion of a hybrid facility's sent-out generation capacity would need to be dispatchable for the whole of the hybrid facility's sent-out generation to be able to follow dispatch instructions, under a single DUID?	Before defining proportions, AEMC need to consider the rationale for reducing participant flexibility in the registration and classification framework. Is the AEMC proposing under option 3 & 4 that (for example) a 20MW storage asset co-located with 100MW of wind /or solar assets would be grouped together as a single hybrid facility and register together (either as a market generator or IRP)? The key concern would be how the scheduled vs semi-scheduled classification then applies to the wind/solar component: - Would the entire facility effectively be a 20MW scheduled generator and load? (this has significant commercial implications for project developments) - Or could it still be considered a combination between 20MW scheduled plus 100MW semi-scheduled generator? Retention of this option is preferred. However, this would then require consideration of appropriate connection and dispatch configurations. It would not be particularly efficient to require some configurations of hybrid assets to have to navigate opaque parent/child metering requirements or continue to seek exemptions for embedded networks behind a single connection point. That said, we strongly recommend a flexible approach is maintained for scheduling hybrid facilities. A site with a mix of load, generation and storage may still want the flexibility to retain/establish separate connection points in order for scheduling obligations to apply at asset

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		level, rather than forcing a single scheduled hybrid facility (which some sites may also seek based on their project specifications). However, regardless of the scheduling approach taken, we agree there is benefit in AEMC looking to unlock the benefits that co-location provide – i.e. avoiding curtailment, optimising excess renewable energy, minimising causer-pay liabilities across the facility etc.
2	Would a dynamic approach to scheduling obligations, for example shifting between scheduled and semi-scheduled obligations based on the state of charge of the storage unit, be appropriate, and how should this operate?	Whilst a directional improvement on the hard-line 'all hybrid facilities are scheduled' approach, dynamic scheduling obligations still remove flexibility for existing assets and introduce additional risk for proposed renewable energy projects that may seek to add storage (either upfront or as retrofit). Consideration also needs to be given to relative proportion of storage vs generation (as per question above) – as a dynamic approach would never make sense when renewable capacity is much larger than storage capacity (and individual projects would have different thresholds for what does make sense). There is a real risk that these new classifications introduce additional barriers to the integration of storage capacity at a time when its uptake is at a critical inflection point (AEMO's 2020 ISP forecasts up to 19GW of storage is required to 2040) to support the transition to a high-renewables grid. We recommend retaining as much flexibility and optionality for project proponents to register and classify their hybrid facilities based on what makes sense at the individual project level – and ideally down to the individual asset level to provide maximum flexibility. This approach may also avoid the additional complication that comes with switching between obligations based on state of charge (or other metrics) – as this could occur frequently over corresponding dispatch intervals and would there introduce additional forecasting complexities.
3	Could the same approach be taken to scheduling load where storage is added to a Market Customer's site, or should different considerations apply?	As above – it may be more optimal to consider storage assets as distinct from co-located load/generation.
Question 5: Number of price bands (p. 21)		
1	Do you agree that 20 price bands would be appropriate for grid-scale batteries or would another number of bands be more appropriate?	Yes. As Tesla has made clear through feedback provided throughout this consultation, we believe that 20 price bands (at a minimum) should be maintained for storage assets – remaining at parity with the existing dual registration model. A reduction in price bands for storage units from the current 20 available would result in a market distortion whereby storage is effectively

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		limited to 5 price bands for bids on energy exported and 5 for energy imported. This would result in significant reduction in bidding flexibility for storage assets. Tesla is not willing to support this rule change if it includes a reduction in price bands available to energy storage units from 20 to 10. Conversely, Tesla would support consideration of additional price bands – e.g. 30 – to recognise the move to a more dynamic and rapidly changing dispatch profile of assets.
Question 6: Dispatching hybrid facilities (p. 21)		
1	Are there certain configurations of hybrid facilities that cannot, or should not, be dispatched at a single connection point?	As noted above, configurations where storage capacity only forms a small (individual projects will each quantify this level differently) proportion of the total site capacity may present a challenge when being classified and dispatched via a single connection point.
2	What benefits are achieved by dispatching a hybrid facility at a single connection point, and what issues arise?	Tesla supports ongoing work in this area, and supports continued flexibility in respect of how to best register variable renewable energy assets and co-located energy storage systems. As per our previous responses to this consultation, we support continued refinement of the proposed hybrid solutions. Specifically we support ongoing work on any hybrid approach that allows developers to maintain optionality with semi-scheduled classifications, but which also can: • Provide fully firmed output from the co-located wind or solar plant; • Best enables storage asset to charge from the renewable plant as well as the grid; and • Reduces causer pays factors across the market participant portfolio.
Question 7: Performance standards (p. 22)		
1	What issues may arise if performance and access standards are set at the connection point for hybrid facilities? Would these standards need to be amended to provide appropriate flexibility for hybrid facilities?	Tesla supports the proposed approach to address asymmetry in current standards between consumption and generation and to implement a single set of performance standards for each asset behind a connection point. Consideration will need to be given to how these new performance standards will impact existing generator performance standards for a market participant seeking to co-locate energy storage with an established wind or solar facility.

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Chapter 3 – Recovery of non-energy costs		
Question 8: Options for the recovery of non-energy costs (p. 27)		
1	Which option do you consider to be the most appropriate for the recovery of non- energy costs from market participants? Please provide detail on why it would be the most appropriate option.	Tesla supports any approach that will address asymmetry between energy exports and imports for the purpose of calculating participant fees, charges and non-energy costs (i.e. some variant of option 3). At a minimum there should be consistency between participants and technology types to level the playing field between different market participants.
2	Are there any other factors the Commission should consider when deciding how non-energy costs should be recovered from market participants?	The AEMC should note that application of these fees across all market customers and generators may have unintended consequences for distributed energy resources (DER), including VPPs and other flexible market participants. As such, Tesla urges caution in applying this same approach at all layers.
3	Are there any implementation issues the Commission should consider?	The other major issue for storage is treatment of T/DUOS costs. Ongoing network usage costs by utility scale storage is a key operational consideration for project developers looking to connect storage assets, and as such Tesla supports the proposal to codify the exemption from T/DUOS charges for grid connected storage assets. Applying a consistent exemption across both TUOS and DUOS assets is vital to optimising the operation of batteries on the distribution network. Utility scale storage connected at the distribution level can provide valuable localised services, and applying DUOS costs to these systems have a significant negative impact on the business case of these assets. It is imperative that any proposed change to network use of system charges consider the role that energy storage assets play in supporting networks and in reducing total system costs.
Chapter 4 – Additional issues relating to storage		
Question 9: Network service provider connection points (p. 34)		
1	Do you support the solution outlined in this options paper for resolving the potential issues with establishing standards for NSP owned energy storage?	Tesla agrees that NSP-led investments in non-network solutions such as battery storage are likely to increase across the NEM. However, further context on the need for AEMO to play a role in approving technical connection standards would be valuable as if this is an edge case of commercial operations, a guideline may be sufficient to address potential conflicts.

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2	If not, do you consider there to be other potential solutions for resolving this issue?	As per the AER's ring-fencing guidelines, NSPs would never be able to operate storage in the market, and so most would likely have a lease agreement with a third-party who could act as the connection applicant (as per the existing arrangements for NSP-owned storage projects to date). In the scenario where there is no market facing operations, the storage capacity would not be participating in the same way as other market generators and loads, and therefore would not need the same negotiated connection processes between two discrete parties – instead the storage facility would essentially become a network asset in the same way traditional poles and wires act to serve an identified network need. In the edge case where the same battery asset is leased to a third party without defined capacity limits – more detail on potential guidelines supporting the connection application process would be helpful in providing transparency and independence to the process.
Question 10: DC coupled systems (p. 38)		
1	What capital, operational or efficiency benefits do DC-coupled systems provide participants and the NEM as a whole, and how might these benefits help consumers in line with the NEO?	Tesla strongly supports further consideration for the integration of DC-coupled systems – noting the efficiency benefits provided to renewable generation projects and the wider grid. This includes reduced capital investment, grid connection, deployment and operating costs – in direct contribution to the long-term interest of consumers. A long-term, fit-for-purpose market framework to support reliability and system security will necessarily rely on the capabilities of all types and configurations of fast-response and flexible resources, including both AC and DC-coupled systems. Efficient registration, participation and incentive mechanisms for all technology types are therefore critical to support the effective operation of the power system and are in the long-term interests of consumers. For context, globally there is already increasing uptake of DC-coupled systems (at all scales) and so we expect the NEM to also include both AC and DC-coupling over time, provided practical barriers can be overcome.

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2	Do you support amending the NER to permit the registration and operation of DC-coupled systems? If so, how should they register and operate?	Yes - the pace of innovation is rapidly accelerating and the AEMC should future proof the framework to ensure all forms of business models, operational profiles and technology portfolios can participate on a fair and equivalent basis. As per scheduling comments above, it is unlikely to be operationally efficient to have both storage and renewable generation assets bound to a single set of operational obligations and technical performance standards at all times and Tesla recommends a more dynamic approach that maintains participant flexibility. Noting the additional implementation complexity involved, Tesla suggests further detail and work is engaged to refine potential solutions to balance the costs and benefits.
Question 11: Provision of ancillary services (p. 40)		
1	Do you support AEMO's proposal to redraft ancillary services provisions in Chapter 2 of the NER to make it more consistent with the services approach to regulation currently being considered by the ESB's two-sided market work? Please explain why or why not.	Yes, Tesla supports the move to simplify FCAS regulatory arrangements to reduce complexity in the registration process and make it easier for new and existing participants to provide new services, and to facilitate innovation in services and market offerings for customers. However, as noted above, some clarification on the classification requirements would be helpful. For example: - We strongly recommend the approach of defining ancillary service units (and allowing assets to provide both generation or load from there). This maintains alignment with the AEMO interim arrangements on FCAS from DER which says that ancillary services load can also participate from a generation perspective. In addition, we recommend that the scope of this rule change is expanded to also allow small generating units to register for FCAS as they have the technical capability to provide such a service. The AEMO VPP Demonstrations trial has clearly demonstrated the technical capability of aggregated, distributed assets in providing appropriate FCAS services. The expansion of the SGA framework to allow participation in FCAS markets would reduce barriers to entry for new market participants, thereby facilitating further demand side participation and competition in the NEM. This is in line with the ESB's two-sided markets work-stream and neutrality principles. We also suggest that the treatment of VPPs should be reviewed as AEMO moves to operationalise their VPP arrangements.