15 March 2022

Mr Daniel Westerman
Chief Executive Officer
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Dear Mr Westerman

Review of NEM Power System Data Communications Standard Issues Paper

Energy Queensland Limited (Energy Queensland) welcomes the opportunity to provide comment to the Australian Energy Market Operator (AEMO) on the Review of NEM Power System Data Communications Standard Issues Paper (Issues Paper). Energy Queensland's responses to questions raised in the Issues Paper are provided in Attachment 1.

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, and affiliated contestable business, Yurika Pty Ltd.

Should AEMO require additional information or wish to discuss any aspect of this response, please contact me.

Yours sincerely

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Attachment 1

AEMO Review of NEM Power System Data Communications Standard

Section	Issue raised	Questions	Energy Queensland comments
3.1.1	Data to be provided - Standard needs to be more definitive on the range of measurements that need to be provided as there is significant uncertainty as to what will actually be required for new connections.	Does the Standard need to be more specific on the range of data covered by the Standard? If so why and what level of detail is considered necessary?	Energy Queensland agrees that the Standard needs to provide a definitive points list, rather than just "Operational Data required by AEMO" to provide greater certainty for participants. It may be appropriate to include a points list as an Appendix or in a separate document. (It is noted that this may already be covered under the ABC and AGC Interface Requirements Technical Specification.)
3.1.1	Definition of power system data - with the growth of embedded generation and the need for AEMO to monitor power flows in distribution systems which impact on the security of the transmission network, this definition needs to be expanded.	Does the definition of power system data need to be extended? If so why and what would be a more appropriate definition?	Energy Queensland questions whether there is a need for separate definitions for 'Power System Data', 'Dispatch Data', 'Other Data' and 'Operational Data' or whether they could all be grouped under one extended definition. Alternatively, it may be appropriate to consider using terms like 'DER Data', 'Transmission Data' and 'Distribution Data'.
3.1.1	Definition of Control Commands - this definition is inadequate as it does not cover the full range of control commands sent out from AEMO NEM Control Centres.	Does the definition of control commands need to be extended? If so why and what would be a more appropriate definition?	As the term 'control commands' and what it encompasses is well understood within the industry, Energy Queensland does not consider that the definition requires amendment.
3.1.1	Definition of RCE and RME – this definition in no longer adequate in context of new technology for data acquisition.	Do the definitions of RCE and RME need to be extended? If so why and what would be a more appropriate definition?	Energy Queensland does not treat RCE and RME as separate devices but rather as two functions of the one device. Therefore we do not consider there is a requirement for

Section	Issue raised	Questions	Energy Queensland comments
			separate definitions. Energy Queensland refers to the device that performs the RCE and RME functions as a Remote Terminal Unit (RTU) and therefore considers 'RTU' should be considered as a replacement term.
3.1.1	Participants in the data communications process – the Standard in Section 1.1 does not include the full range of participants involved in the data communications process.	Other than the changes required to accommodate additional participant categories identified in clause 4.11.1 of the NER, does the Standard need to extend or specify other participants or sub-groups within a category. If so, how and why?	Rather than changing the Standard to specify each participant individually, Energy Queensland considers inclusion of a generic statement, such as 'The Standard applies to Participants, including but not limited to:…', would be more appropriate.
3.1.1	Definition of Analogue Value	New issue for consideration.	Energy Queensland considers that use of the term 'Digital representation' at first glance implies a Digital or Status indication, which is different to the intent. We therefore suggest replacing the word 'Digital' with 'Numeric'.
3.1.2	The requirements set under the Standard for different classes of data need to take into account the use of the data and its criticality.	Should requirements under the Standard be varied according to how critical the data is? If so, what criteria should be used to determine the requirements particular data needs to meet?	In Energy Queensland's view, the data requirements set under the Standard should only be varied if the actual requirement is different and the actual requirement should determine the criteria the data must meet. In our view, there may be potential to reduce the classes of data to two or three classes.
3.1.2	The standard is not consistent with more stringent requirements in some areas (e.g. Market Ancillary Service Specification).	Are there examples where AEMO has specified requirements beyond those set in the Standard, and how	Any specific requirements could be itemised in the detailed points list.

Section	Issue raised	Questions	Energy Queensland comments
		can any potential inconsistencies best be reconciled?	
3.1.2	The standard seems to assume that all participants in the data communications process operate data centres.	Are there examples where the Standard has not kept pace with developments in data communications technology?	In our view, the diagram in section 1.3 of the Standard (General structure of DCFs) is ambiguous and does not reflect current state. For example, the diagram implies that each substation has a primary and backup communications path, which is not correct for most DNSPs.
3.1.2	There is an opportunity to design vulnerability out and design security in, as opposed to putting in place processes to manage the emergence of security issues. It might be possible for the Standard to encourage enhancement of resilience through design.	Is there an opportunity for the standard to encourage enhancement of resilience through design? If so, how might this be done?	Energy Queensland considers there is an opportunity to encourage enhancement of resilience through design. This could be achieved by amendments to section 4 of the Standard (Security). In our view, the requirements specified in this section are non-negotiable and the language used should reflect this (for example, by amending '... should use reasonable endeavours to address...' to 'must address' in the second paragraph). Consideration should also be given to providing further specification of cyber security requirements.
3.1.2	The Standard to be clear on the consequences for a participant failing to meet the requirements of the Standard.	Should the Standard set out the consequences for a participant failing to meet its requirements?	Energy Queensland agrees that it may be beneficial for the Standard to clearly set out the consequences for participants if they fail to meet requirements. There may also be value in considering a compliance and enforcement regime to ensure participants comply with the requirements of the Standard.

Section	Issue raised	Questions	Energy Queensland comments
3.1.3	The requirements specified for DNSPs may be unclear in a number of areas. Possible examples are: • Current standard does not reflect topology that applies for DNSP (e.g. diagram in Section 1.3 and tables 4 and 5). • Standard needs to state whether or not DNSP can have direct connection with AEMO rather than going through TNSP • Standard needs to account for diversity in comms between TNSP/DNSP to AEMO. • Standard should include situation where there are two intervening facilities and perhaps more.	What changes to the current Standard are required to clarify the requirements for DNSPs?	Energy Queensland provides the following comments regarding requirements for DNSPs that may require clarification or amendment: • As previously noted, the diagram in section 1.3 (General structure of DCFs) is ambiguous and does not reflect current state. For example, it implies that each substation has a primary and backup communications path, which is not correct for most DNSPs. • Section 3.2 (Redundant elements) and the diagram in section 1.3 potentially contradict each other as our understanding is that redundant communications paths are not required if the reliability requirements set out in section 3.1 can be met. • The timeframes set out in Table 4 (Total period of Critical outages of RME and RCE over a 12-month period) may not always be achievable for DNSPs, depending on the situation. For example, if an RME/RCE fails in a remote location and parts are required, it could take a week or more to return the device to service. • Tables 4 and 5 (Total period of Critical outages of Intervening Facility over a 12-month period) do not take into account where there are multiple intervening facilities (for example, a solar farm passes data to the DNSP who passes the data to the TNSP who passes the data to AEMO).

Section	Issue raised	Questions	Energy Queensland comments
			• DNSPs, and potentially other participants, should be permitted to directly connect to AEMO rather than going through the TNSP. This capability would reduce ambiguity around reliability where there are presently multiple intervening facilities. The Standard is, in our view, the appropriate place to address connectivity options.
3.1.3	The current structure is making it difficult for new connections.	Are there specific examples where the current data communications structure is making it difficult for new connections or embedded participants? If so what changes in the Standard would be required to address these issues?	By not allowing participants to directly connect to AEMO, they have no other option than to go through an intervening facility that may not be able to prioritise connections to suit the participant. The participant is also then subject to costs charged by the intervening facility with little ability to negotiate or seek alternative solutions.
3.1.3	It is reported that wholesale demand response providers are finding it very difficult to be connected for data communications under current arrangements.	What difficulties are wholesale demand response providers finding to be connected for data communications under current arrangements?	Energy Queensland's understanding is that difficulties may be occurring because connection agreements are finalised without technical and data communication requirements being fully understood. It is important that participants are equipped with a sound understanding of the technical requirements of their project at an early stage.
3.1.3	New embedded scheduled and semi-scheduled generators have obligations under the rules and Generator Performance Standards (GPS) to participate in Automatic Generation Control (AGC).	What difficulties do DNSPs have in communicating AGC control signals?	Issues may be experienced with timing / data latency requirements, especially via an intervening facility.

Section	Issue raised	Questions	Energy Queensland comments
	However, some stakeholders have indicated that this is not possible through some DNSP SCADA systems.		
3.1.4	The current standard specifies ICCP IEC60870-6 TASE.2 and its extensions as a secure ICCP protocol. A stakeholder has questioned whether this can actually be considered as a secure protocol.	Is the current ICCP Protocol specified in the current Standard still appropriate?	It is our understanding that the current ICCP with Digital Certificate Management uses encryption and authentication on the transport layer. Energy Queensland considers this is appropriate and secure.
3.1.4	The Standard in Section 5.1 should be more specific on protocols used when AEMO WAN is connected to another party's data Communications Facility.	What protocols should apply for connections to AEMO WAM?	The ICCP is a protocol developed between control centres. Therefore, if a participant is connecting directly and not via an intervening facility (control centre), they may not have ready access to the ICCP protocol. In this situation AEMO should consider other standard industry protocols, such as DNP3 and Modbus, and potentially other emerging protocols and standards, such as IEC61850 and IEEE2030.5/CSIP. If the ICCP is required, smaller participants may incur additional costs to implement via a protocol converter.
3.1.5	The Standard should provide more clarity on the boundary of both operational and financial responsibility between • Generator and NSP • DNSP and TNSP • AEMO and TNSP	What additional detail is required in the Standard to provide more clarity on boundary of both operational and financial responsibilities?`	The Standard should emphasise that it is the generator's responsibility to ensure required data is provided to AEMO, whether via a direct connection or an intervening facility. Issues relating to responsibilities could be addressed by removing the need for intervening facilities and permitting generators to directly connect to AEMO.

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3.1.5	The standard should make clear the obligation of parties to work together to resolve any problems to ensure a requirement is met.	Should an obligation for parties to work together be added to the Standard?	Energy Queensland supports a high-level obligation for parties to work together to resolve issues.
3.1.5	The Standard needs to be clear that connections are required to both AEMO control room sites.	Does the Standard need to clarify that connection is required to both AEMO control room sites?	Intervening facilities are already well aware of AEMO's connection requirements. However, further clarification may be required if direct connections to AEMO are permitted.
3.1.6	The Standard needs a specific requirement that data sent is of good quality. It is possible for a connection to be available and the data to be unusable due to quality.	Should the Standard include a specific requirement that data sent should be of good quality? If so, what would be implications for stakeholders?	Data Quality flags are implied in the use of the ICCP protocol, and briefly mentioned in Section 2.2(e) of the Standard. However, to avoid doubt, it may be beneficial to provide further clarity in that section.
3.1.6	Some remote metering equipment does not provide quality flags.	Should all data be sent with quality flags? If so, what would be implications for stakeholders?	In our view, Data Quality flags are essential and should be a requirement for stakeholders to include in their design. Most SCADA protocols include some form of data quality.
3.1.7	The Standard does not have an effective requirement to ensure the accuracy of data in particular to ensure that RME remains calibrated. Monitoring and remediation may be problematic (e.g. kv measurements at some stations can vary by over 10kV).	Should the Standard include a more specific requirement regarding data accuracy? If so, what would be implications for stakeholders?	DNSPs and TNSPs will have their own data accuracy requirements, so more specific requirements are not necessary for those participants. Generators should be designing to a certain level of metering accuracy. If accuracy is a problem that AEMO is experiencing, calibration requirements at appropriate intervals should be specified in the Standard. However, additional participant costs will need to be taken into consideration when determining these requirements.

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3.1.7	All semi-scheduled units being clamped in SCADA (at the AEMO end) such that telemetered MW values could not be negative is undesirable, noting that participants are responsible for providing accurate data and separate metering of auxiliary loads.	How material is the issue regarding clamping of values for semi-scheduled units? If the standard were to be changed as suggested, what would be the implications for participants?	Energy Queensland does not consider that clamping is appropriate for two-way power flows as it is important for AEMO to see both negative and positive values, particularly as great volumes of batteries are deployed.
3.1.8	The Standard is not clear on requirements for data latency or end-to-end response times. There is current no minimum requirement for data latency.	Should the Standard include a specific requirement regarding data latency? If so, what would be implications for stakeholders?	While data latency is addressed in section 2.3 (Age of Data, Table 2 (Time intervals for data to be available for transmission to AEMO) is difficult to interpret and does not account for multiple intervening facilities. Energy Queensland also questions the need for a separate time interval for data transmitted through a data concentrator. In our view, only one time interval should be specified and clarity provided that the time interval should include any time within an intervening facility.
3.1.8	Significant timing difference can exist particularly for the RME equipment that uses UTC time and the conversion of this to AEST. There should be greater clarity on the requirements for calibration, testing, validation, and maintenance of the timing stamp quality.	How material is the issue regarding timing differences due to RME? If the standard were to be changed to address this, what would be the implications for participants?	There may be value in adding a section regarding time-stamping requirements. These requirements may include a GPS clock signal or time via a network protocol and would also need to include the expected timestamp resolution, e.g. minute, second, millisecond, etc. However, depending on the specific requirement, this could be a significant overhead for the participant, particularly if installation of a GPS clock is required. Notwithstanding, accurate time should be available within the participant's design.

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3.1.8	Monitoring end-to end update times is difficult post commissioning	Should an additional requirement be included in the Standard to allow ongoing monitoring of end-to-end response times? If so, what would be the implications of such a change?	Ongoing monitoring of end-to-end response times would be very difficult and onerous to undertake, and several factors would need to be considered. For example, the time of day testing is performed may impact round-trip time due to network congestion. Further, issues such as responsibility for paying testing costs and whether intervening facilities will also need to be involved will need to be considered.
3.1.9	AGC is showing performance issues which suggest that a more responsive control loop is needed. With the current 4 second AGC cycle, updates at a minimum of less than 2 seconds may be required. There have been incidents where AGC used to control a battery is stale (20s old) resulting in unwarranted discharge and charge cycles and at times oscillations. This is mainly because the communications delay is more than 97% of the response delay time	What would the implications be if the specification of maximum delay for control commands was tightened to 2 seconds? What are the implications if control command delays remain at current levels?	In our view, a review of the entire communications network would be required to meet the proposed 2 second timeframe, particularly where intervening facilities are involved. Significant costs may be involved in changing the communications infrastructure to meet tightened timeframes.
3.1.9	There should be increased use of dispatch signals via SCADA through the NSP as AEMO's Market Portal may be unreliable and any failure to meet dispatch requirement increases system risk.	Is there a material issue associated with reliability of the connection to AEMO's market portal?	Responsibility for reliability of the Market Portal rests with AEMO and any performance issues should therefore be addressed by AEMO. Dispatch signals through the NSP should only be used as a last resort or backup option, not as an alternative to a poorly performing system.

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3.1.9	The specification of maximum delays may not adequately take into account the number of intervening facilities through which the command signal needs to be relayed.	Should the specification of control command delays in the Standard take into account the number of intervening facilities? If so, how should these be accounted for and what would the implications be?	In our view, the best option is to specify one time interval. That time interval should take into consideration the involvement of any intervening facilities.
3.1.10	The current standard is not clear on obligations of the parties to the security of the data (physical, personnel and cyber) and of control protocols at the level required for critical infrastructure.	What specific obligations regarding maintenance of security should be included in the Standard, and what would be the implications of this?	In our view, there is no requirement for these obligations to be covered in detail in the Standard. Rather, the Standard should reference the Australian Energy Sector Cyber Security Framework and *Security of Critical Infrastructure Act*.
3.1.10	Alignment between this data communications standard and these current and proposed regulations requires consideration.	Does the legislation adequately cover security obligations and requirements or is there a need for more detailed obligations in the Standard?	Energy Queensland does not have any comment.
3.1.10	The Standard should include an obligation for participants to advise AEMO of any known relevant cyber security issues or when abnormal risks to cyber security arise.	What would be the implications of including a specific obligation to advise on cyber security risks?	It is Energy Queensland's expectation that DNSPs would notify AEMO of a cyber security risk. It is not clear that there would be any value in including a specific requirement in the Standard.
3.1.10	There are questions about ownership and control and rights to data, and when. While not specifically related to the Standard, the standard should nonetheless fully support and enable these requirements.	Should the Standard be enhanced to better identify and support the protection of the confidentiality of data? If so what type of enhancement is required?	Confidentiality of information requirements are made clear in section 4.1(d) and note 3 of the Standard. However, there may be a need to add further detail with some commentary regarding ring-fencing obligations.

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3.1.11	There is a need for greater clarity in Section 3.1 of the Standard regarding the specification of reliability requirements. In particular: • In table 4 standard term RCE needs to be better defined • Tables 4 and 5 are not clear. For instance does the 6 hour requirement apply to a single site or all sites? • Possible inconsistency between table 4 and 5 • Difficulty in seeing how tables 4 and 5 apply to DNSPs • Need to better define what is meant by a critical outage in Section 3.1 - i.e. does it refer to total loss of data or simply loss of redundant path?	What changes would be required to clarify reliability requirements in the Standard?	The following changes are suggested for consideration: • Replace tables 4 and 5 with an availability figure. • In practice, the three categories in Table 4 will most likely always have the same outage timeframes. Similarly, with respect to Table 5, if the intervening facility has an outage for Power System Data, there will likely be an outage for Dispatch Data as well. • The timeframes specified in Table 5 for intervening facilities need to be fair and reasonable given intervening facilities are merely facilitating data transfer between the generator and AEMO. Otherwise, there is a risk that the intervening facility will need to build in reliability requirements that are greater than their own needs. • Energy Queensland agrees clarity is required about loss of some points, total loss of points, or loss of redundancy (if applicable) in the definition of Critical Outage. • Clarity is required with respect to responsibility for notifying AEMO of a planned outage (i.e. the generator, DNSP or TNSP) and the circumstances in which AEMO must be notified.
3.1.11	The Standard should set expectations on the level of monitoring and reporting of reliability required. For instance, this might include a	Does the Standard need to set enhanced expectations regarding monitoring and reporting of availability and why?	As participants will incur additional costs to meet enhanced expectations, changes should only be made to the Standard where AEMO is experiencing issues with data reliability.

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	comprehensive heartbeat facility	What would be reasonable expectations to set? What changes would be required to data communications systems to achieve enhanced monitoring and reporting of availability?	
3.1.11	Frequent and rapid applications of software patches is becoming an increasing requirement for maintaining cyber security. One stakeholder has queried whether new or additional redundancy may be needed at DCFs to allow rapid application of patches without disrupting operations.	Does any lack of redundancy currently restrict the ability of participants to apply software security patches in a timely manner?	Software patching should be managed by each individual participant as required. For instance, DNSPs already have redundancy built into their systems such that patching does not affect their day-to-day operations.
3.1.12	Section 2.2 of the current Standard states that "DCPs must notify AEMO of their sign convention when applying to AEMO for registration as a Registered Participant. To change the sign convention, DCPs must give 60 business days' notice to AEMO". It is not clear whether this requirement applies to small scale changes to correct individual sign conventions or only to a major change following a change in policy.	What change to Section 2.2 of the Standard would be required to clarify the requirement for adequate notice?	In Energy Queensland's view, greater emphasis should be placed on the sign convention in the Standard. In our view, the sign convention should be the same for all participants and not subject to change. Further clarification on the sign convention could be provided in the Standard, e.g. that power direction is relative to the DER source, such that if a generator is exporting it is negative, or if a battery is charging it is positive.

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3.1.13	The Standard has no specific requirements for the times required to return to service following forced outages and in practice failed data can take a long time to rectify. Tables 4 and 5 of the current Standard refer to a reliability requirement rather than a specific response time.	What issues have arisen that would justify including in the Standard a specific requirement regarding response time to forced outages? If so, what would reasonable expectations be?	Unless AEMO is dependent on the service, Energy Queensland does not see the need for setting response times for forced outages.
3.1.14	The current testing scope does not include testing of whether the data is correct, but only that data is being communicated. The scope of testing specified under the Standard could also include testing for cyber security; and robust RCE and RME testing, calibration and validation.	What issues have arisen that would justify expanding the scope of testing specified in the Standard? If so, what increases in scope are required? What would be the implications of a change in testing scope?	In Energy Queensland's view, participants should be responsible for testing their own assets. The Standard should not need to address the level of testing required for the actual plant. The Standard should assume that data points have been appropriately tested and commissioned to a control system, and that data flowing to AEMO is commissioned data. Basic checks should only be required, such as: • for digitals - check the status (no need to re-field test); and • for analogues - check the current value (no need to test at 0, 50% and 100%). It may be worth considering full end-to-end testing of controls.
3.1.14	The level of testing required for new generators is onerous.	What are examples of testing requirements that are considered too onerous for new generators? Are there opportunities to make these requirements less onerous without materially reducing the effectiveness of the testing	As per the above, if points have already been fully tested and commissioned to a control system, then they should not need to be fully retested to AEMO.

Section	Issue raised	Questions	Energy Queensland comments
		programme in demonstrating the necessary capabilities?	
3.1.14	Section 6.4 of the current Standard is not clear on what constitutes an “upgrade”.	What changes to the definition of an “upgrade” is required? What implications would such a change have?	Energy Queensland considers that the intent of the term ‘upgrade’ is clear and that a definition is not required.
3.1.14	The requirement under Section 6.4(c) of the current Standard is unclear and that for the sake of efficiency it should encourage the use of standard test procedures.	Should section 6.4(c) of the current Standard be amended to encourage use of standard test procedures?	Energy Queensland agrees that standard test procedures and test plans should be available.
3.1.14	Due to the changing nature of the power system the requirements for advice on augmentations under the Standard need to be increased.	What issues have arisen that would justify expanding the scope of augmentations required to be advised under the Standard?	Data updates regarding network augmentation are typically managed by the TNSP (or DNSP) independent of this Standard.
3.1.14	The Standard needs to require the provision of an appropriate testing environment for data links.	What issues have arisen that would justify the Standard specifying the provision of testing environments for data links? What implications for stakeholders would such a new requirement have?	A testing environment may be helpful. However, it is not clear that it should be included in the Standard.
3.1.15	Any increased requirements in the Standard need to be transitioned to accommodate additional funding requirements to meet such increased requirements.	In what circumstances would transitional provisions be justified for increased requirements in the Standard? If justified, what form of provisions would be	DNSP funding is generally determined in five-yearly regulatory control period cycles. Any major updates (e.g. adding full communications redundancy to all substations) requires significant investment and approval by the AER. If a transitional decision is made at

Section	Issue raised	Questions	Energy Queensland comments
		needed and for how long?	the start of an investment cycle, it could be another four to five years before funding is available, and a further five to ten years to outwork the changes.
3.2.1	AEMO NEM Control Centres currently use limited real time data from PMUs. In the near future the level of this real time data from PMUs and High-Speed Monitors (HSMs) will greatly increase and requirements for the communication of these data types may need to be included within the Standard.	Does the Standard need to cover PMU and HSM data? If so why and on what basis should the requirements be set (i.e. appropriate standards on which the requirements could be based)?	If this data is required by AEMO, it should be included in the detailed points list. In our view, AEMO should also contribute towards funding that capability.
3.2.1	Some stakeholders have noted that the Integrating Energy Storage Systems rule change will enable Small Generation Aggregators (SGAs) to provide FCAS and that the Standard may need to accommodate this change.	Does the Standard need to cover SGAs? If so why and on what basis should the requirements be set?	If AEMO is dispatching and monitoring SGAs, then the Standard should include the specific requirements determined by AEMO.
3.2.1	The Scheduled Lite Visibility Model to provide visibility to AEMO of the output in the form of five-minute data may be required by mid-2022 and this may need to be accommodated in the Standard.	Are changes to Standard required now to accommodate the first stage of the Scheduled Lite Project? If so, what changes are required?	Energy Queensland has no comment.

Section	Issue raised	Questions	Energy Queensland comments
3.2.1	The Scheduled Lite Dispatchability Model is expected in 2024-25 to enable distribution connected aggregated DER to participate in central dispatch	What future changes to the Standard are likely to be required to accommodate the second stage of the Scheduled Lite Project?	Energy Queensland has no comment.
3.2.1	In the future there may be a requirement for AEMO to also provide real time data to participants.	Is it likely that future changes to the Standard will be required to also cover provision of real time data from AEMO to participants?	If AEMO is providing real time data to participants, then it should be included in the detailed points list.
3.2.1	Whilst provision of real time to NSPs from Generators and others is not within the scope of the Standard, it remains part of the overall data communications process in the NEM. For instance even if, say, a generator was to provide real time data directly to AEMO, there may still be a requirement for the generator to provide data separately to its NSP.	Regardless of provision of data to AEMO, does the Standard need to incorporate or reference requirements for generators and others to provide real time power system data to their NSPs?	In our view, this requirement should be covered by connection standards and connection agreements between participants and NSPs. Energy Queensland's DNSPs are already doing this.
3.2.1	Enhancements to the Standard will bring benefits but also may result in increased costs to the industry and ultimately consumers. It is possible that costs may be disproportionate in the case of enhanced requirements for smaller participants, however the necessity for those requirements	Are there any specific factors AEMO should take into account in assessing the costs and benefits of a proposed enhancement to the requirements of the Standard?	AEMO should take factors such as the following into consideration when undertaking a cost-benefit analysis: • resource availability; • timeframes for implementation; and • the fact that where there are multiple intervening facilities, the participant may not only be required to pay their own costs, but also those of the DNSP and TNSP.

Section	Issue raised	Questions	Energy Queensland comments
	may increase as the relative numbers of smaller participants increase.		
3.2.2	In the near future, a growing number of embedded battery generation, aggregated DER and VPP connections will need to be accommodated. Some stakeholders believe that this will mean that the current data communications structure will be no longer fit for purpose.	What changes to the current NEM power system data communications structure are likely to be required? Are there different options for such changes?	While it is difficult to predict future requirements, current industry protocols, such as ICCP and DNP3, have stood the test of time. It is likely that NSPs will keep up-to-date with modern protocols (e.g. using a DERMS to communicate directly to inverters), so the solution may need to loop back to mandating intervening facilities. Alternatively, AEMO may need to introduce their own systems rather than relying on intervening facilities. Energy Queensland's DNSPs are introducing a DERMS in the near future as an independent system to their DMS/SCADA systems. Consideration should therefore be given as to whether AEMO should be communicating directly with the DNSPs' DERMS, (and those of other NSPs) in addition to the current connection to AEMO via the TNSP.
3.2.3	Under the current architecture as described in Section 3.2.2, the only communication protocol support for connection to AEMO is the ICCP protocol. If a change in the data communications structure is required, then it may be necessary for the Standard to accommodate alternative protocols for connection to AEMO. The ICCP	If generators and other participants were permitted to communicate directly with AEMO, then what types of data protocols would be preferred? If for cyber security and other reasons, only a single protocol can be accommodated in addition to secure ICCP, what criteria should AEMO use to determine the most suitable protocol?	Ideally, the preferred protocols would be the proven standard industry protocols, such as DNP3 and Modbus, but also other emerging protocols and standards, such as IEC61850 and IEEE2030.5/CSIP. Generally, it will depend on the requirements, e.g. Modbus, though quite robust, does not allow time-stamping of data. If a new protocol is added then it will need to be available to and accessible by all participants. A protocol like 2030.5 is most likely the best suited protocol for future requirements, but not all

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	protocol is designed for data communication between control centres and would not be suitable if a generating unit were to communicate directly with AEMO.		participants will have access to it in their systems. Therefore, in our view, DNP3 is the best overall option as it is well-known and easy to implement and convert to if it is not a native protocol within a participant's system.