AEMO review of technical requirements for connection

26 July 2023

Appendix A1 to Draft Recommendations Update Report (Part 1) – Schedules 5.2 & 5.3a of the National Electricity Rules – Stakeholder consultation analysis and revised recommendations

Important notice

Purpose

This document is Appendix A1 to the Draft Recommendations Update Report published as part of AEMO's periodic review of the technical requirements for connection in the National Electricity Market, under clause 5.2.6A of the National Electricity Rules. This document summarises stakeholder feedback received for each draft report recommendation, analyses feedback received, and sets out reasons for AEMO's decision to either revise or retain draft report recommendations. It is an interim report published for consultation purposes only.

Disclaimer

Copyright

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

1 General feedback

Issue	Schedule 5.2 Generator recommendation feedback summary	AEMO position
Grid forming /modern inverter capability	**EUAA** • The EUAA recommends that AEMO and/or the AEMC consider that the minimum standard for inverter-based generation is reviewed to align with modern inverters. EUAA believes this will reduce the need for the requirements for specific clauses in the NER. For example, specifying a minimum standard comparable to the grid forming inverters that respond to voltage, will react and correct over- and undervoltage conditions and frequency variations quicker than the current proposed changes to Schedule 5.2 above. In this way, and similar to the proposed changes to Schedule 5.3, AEMO can better manage inverter-based contributions to the market and system security into the future when it is expected that high percentages of generation are provided through inverter based variable renewable energy.	Noted. AEMO's position for this review is that the technical standards should enable grid forming inverter technology by removing impediments to its connection, but not preclude other technologies. Making the MAS a higher standard to reflect GFM inverter capabilities might preclude existing technologies, which is not intended.
AEMO Guidelines to support connection	**APD** • APD Engineering recommends AEMO provide a clear guideline for implementation and assessment of the rule amendments, made available in unison with the implementation of the rule amendments to minimise impact on connection projects.	Noted, however, this is outside the scope of this current review. AEMO will review the need to update or develop guidelines as a separate exercise.
S5.2.5.1 Negotiation framework	**CEC, CPSA** • The 2018 rule change required generators to meet the AAS irrespective of the GPS clause. Meeting the AAS for S5.2.5.1 can require the installation of additional plant resulting in increased capex for projects. Where there is no system need for additional reactive power, then the need to meet the AAS should be relaxed or the onus of proof placed upon the NSP to prove a system need and nominate the required level of reactive power.	Changing the negotiation framework is beyond the scope of this review. However, we have reduced the requirements of S5.2.5.1 for reactive power performance to align better with the needs of the power system.
Intent and compliance assessment of S5.2.5.7	**Hydro Tasmania** • HT would encourage AEMO to provide some clarification on: – the technical intent of this assessment, particularly the specification of 30% load reduction in less than 10s. – whether or not the existing specification is practical to measure and to be considered as a performance reference, particularly given the power system is getting more scattered and the boundary is more blurred between the generators and loads, or otherwise if there is a better definition.	The original clause was drafted for synchronous machines and related to partial load rejection capability of those plant. The rule was extended to asynchronous generation in 2018 and more recently has also been applied to bidirectional units under the Integrated Energy Storage Rule Change. It is intended to capture extreme events. There has been some experience with testing the clause on large synchronous units in the past, with a trip to house load. However, generally it is assessed through simulation, and review of any major overfrequency events. Such events may combine elements of faults, over-frequency disturbances and system strength reduction. While 30% load reduction has low probability, there have been historical incidents where the 5% MAS has been exceeded.

Issue	Schedule 5.2 Generator recommendation feedback summary	AEMO position
Protection Systems S5.2.5.9 – redundancy provisions	**Rod Hughes Consulting** • Rod Hughes wishes to draw AEMO's attention to a separate rule change proposal in relation to S5.2.5.9: https://www.aemc.gov.au/rule-changes/conditions-generator-protection-systems	Noted. Recommended changes will not interact with this proposed change.

2 Feedback on Schedule 5.2 Conditions for Connection of Generators

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
NER S5.2.1 – Outline of requirements		
Application of Schedule 5.2 based on plant type instead of registration category and extension to synchronous condensers	**AGL – Supports** • AGL supports the proposal to amend NER S5.2.1 to provide that references to generating systems, synchronous generating systems and synchronous generating units are taken to include synchronous condensers, provided that the carve outs are quite specific. **Amp Power – Support** • Amp Power supports AEMO's recommendations. **APD – Alternative option proposed** • APD agrees with AEMO that more clear and unambiguous definitions should be provided for synchronous generators, synchronous condensers, IBRs, BEES, IRPs etc. • Suggests defining separate requirements for different technologies eg S5.2.5.5, the schedule may have separate sub parts defining the performance for synchronous generators, syn cons, IBRs, BEES, IRPs separately without any mix-ups making it clearer and more distinctive according to the generation type. **AusNet – Support (for Part A)** • AusNet supports the proposed option (3). **AusNet – Alternative option (for Part B)** • AusNet suggests that S5.2 should be extended beyond synchronous condensers to other plant: it should be applied, with appropriate thresholds, to power electronics based flexible alternating current transmission systems (FACTS) technology like grid forming/following Static VAR Compensators (SVCs), Static Compensators (STATCOMs), and Static Synchronous Series Compensators. • Strengthening the technical standards, monitoring and compliance requirements could potentially lead to a more efficient and effective process for connecting network auxiliary service devices to the NEM power system, which could benefit both generators and consumers. **Energy Queensland – Support** • Ergon Energy and Energex are supportive of consistency in assessing the connection of plant that can have a significant impact on the network such as synchronous condensers.	Respondents generally support changes proposed to reorient the schedule to performance of plant rather than application by reference to the registered participant. AEMO notes that these changes would affect synchronous condensers within generating systems as well as standalone plant. As per usual practice they would not affect existing plant unless it is upgraded or otherwise changed. AusNet suggests extending Schedule 5.2 to include other dynamic reactive plant such as FACTS, SVCs, Statcoms and Static Synchronous Series Compensators. AEMO acknowledges that there may be some benefit in having consistent performance requirements established for such equipment across the NEM, however, does not propose to progress such changes under this Review given the significant effort and consultation required. If progressed in a later review, consideration would need to be given as to whether another schedule might be a better fit (eg schedule 5.3a or schedule 5.1) or if a new schedule would be required. In the case of synchronous condensers, there is a significant level of commonality between their characteristics and those of synchronous generators. AEMO considers there should be sufficient scope within the existing generator access standards to allow for different applications of synchronous condensers, provided the schedule is made to apply (in other words, relevant technical requirements ought to apply to anyone who owns, controls or operates this equipment regardless of registration category, if any). AEMO acknowledges the trend toward convergence of generation and load technologies with inverter-based equipment, but there is a much broader range of load technologies employed, not all of which would be capable of performance like IBR generation. It is noted, regarding issues raised about the application of the NER 5.3.9 process, that the application of NER 5.3.9 processes are currently under review as a workstream under the Connections Reform Initiative. Work on this will progress over 2023. In the proposed drafting AEMO has adopted the terms Schedule 5.2 Participant and Schedule 5.2 Plant. Using these descriptors it is possible to be

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	EUAA – Support; issues raised • The EUAA supports the inclusion of synchronous condensers in the rules pertaining to performance standards as well as the shift to plant type instead of registration category. By recognising the specific characteristics and limitations of different generator types, the EUAA believes that these changes will ultimately lead to a more secure energy system. • However, care must be taken in ensuring that the term chosen (connected participant or registered participant) to replace the current terms (Generator and Integrated Resource Providers) does not inadvertently confer these rules intended for Generators and network service providers on other categories of Registered Participant such as “Customer” (Schedule 2.3 of the NER). • The EUAA recommends that if either of the proposed terms “Registered Participant” or ”connected participant” is used to replace Generators and Integrated Resource Providers, that a list of exempt Registered Participants per Chapter 2 of the NER is included. **Hydro Tasmania – Support with clarification** • In principle, Hydro Tasmania supports AEMO’s recommendations for both parts A and B with the caveat of further review to proposed drafting (for part B) to ensure minimal drafting effort does not result in complexity that could have been avoided with part B option 3. • It is noted that Hydro Tasmania has a significant number of existing NEM registered Generating Units that also operate in Synchronous Condenser mode generally to provide inertia and fault level support to the power system. These units are registered as generating units only. Although the reference in the paper appears to reference stand-alone synchronous condensers it is unclear from the proposed changes what the implementation of Schedule 5.2 requirements to ‘synchronous condenser’ means with respect to an existing synchronous generator that can also operate in synchronous condenser mode. • Clarity around this issue is important as these generators are regularly upgraded, with revisions to the performance standards assessed under the NER. • 5.3.9 process. For the sake of clarity Hydro Tasmania requests that AEMO provide a clear outline of how the performance standards and related matters (do or do not) relate to Synchronous Generators that also operate as Synchronous Condensers so that a more detailed response could be considered. **TasNetworks – Supports in principle** • TasNetworks supports the broad principle of applying Schedule 5.2 on the basis of plant type rather than registration category. There are some implications that are worth considering such as who negotiates with whom when a transmission network service provider wishes to connect a synchronous condenser to its own network. There also may be situations where basing standards solely on the type of technology could be unnecessarily restrictive. The same technology could operate in different ways depending on whether it is a load/generation or a network and thus the performance expectations may be different.	specific about who and what the schedule applies to. AEMO acknowledges EUAA’s comments about the application of the schedule, and would welcome feedback on whether the proposed drafting addresses this concern. **Revised recommendation** Considering the feedback, AEMO proposes to retain the Draft Report recommendation.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Additionally, given the increased likelihood of bi-directional connections (as, for example, wind farms include batteries behind the connection point) it could even be challenged why there is a different set of standards for generation and load. **Transgrid – Support (for Part A)** • Transgrid agree with the recommendation to pursue Option 3, to ensure a consistent approach across the NEM on application of technical standards to synchronous condensers. **Transgrid – Support (for Part B)** • Transgrid supports Option 2 for application of NER S5.2 standards to synchronous condensers.	
NER S5.2.5.1 – Reactive power capability		
Voltage range for full reactive power requirement	**AGL – Supports** • AGL is supportive of this proposal for new connections but note that caution must be applied should such requirements be imposed on existing generators (e.g., through a cl.5.3.9 process), as some existing generators would not be able to meet this standard. **Amp Power – Support – partial** • Amp Power supports the introduction of the 10% voltage band with reduced reactive power requirement at high voltage (injection) and low voltage (absorption). • Concerned about allowing the NSP to select the centre point, in absence of a well-defined methodology. If too high it might require the plant to be rated higher than 110% of normal voltage. • Propose to fix the centre point or at least require it to be in the range 95% to 105% of the nominal voltage. **APD – Support; issues raised** • APD supports the proposed option. • Requests AEMO to consider the timeframe obligation for the NSP to confirm a suitable centre-point, with standardised documentation. • Change to the centre-point voltage during project due diligence would significantly delay overall connection process, and APD observes that change to nominated [target] voltage often occurs. This should be avoided through implementation of a formal process accompanying the rule change. APD would welcome a rule obligation on NSPs to avoid such a thing. • APD notes that in some parts of the network far from load centres currently synchronous generators are often operated at their full reactive capability, for example at 1.08 to 1.09 pu PoC voltage, to support voltage at load centres. When the synchronous generators are replaced with IBRs with limited reactive support at high voltage range there will a possibility to compromise the reactive support at load centres. Such impacts of this rule change also need to be considered. It should be practically considered by assessing how the generators	The majority of respondents support the proposed changes. The main concerns seem to be around the NSP's role in setting the centre point for the voltage range, and that that might lead to voltages above 110%. AEMO believes that the NSP is best placed to know the expected voltage range of the network, and to advise the centre point of the voltage range. However, AEMO intends that reactive power be specified within the range of 90 to 110% of nominal voltage (More on this below). AEMO acknowledges that it would be reasonable for the value to be made available at the connection enquiry stage. AEMO is also of the opinion that a range of +/-5% around a centre voltage gives sufficient range for variations in system voltage over time (considering also that full absorption capability is still required up to 110% and full injection down to 90%), and questions the assertion from Transgrid that the range for full injection and absorption might need to change over the life of the plant. Transgrid raised an issue around limits being applied at the AAS level artificially restricting the reactive range, and limits on voltage requirements encouraging this trend. It is reasonable for a generator to restrict the reactive power to the AAS level where not doing so would expose the plant to voltages higher than the design voltage. Operation for extended periods above design voltage may be expected to reduce the life of the plant. On the other hand, operation at (slightly) higher voltages for short durations where the plant is capable it, might not do any harm. On the other hand, the availability of additional reactive capability during periods in which the power system is under stress, is advantageous to power system resilience. Additional reactive power provision where it is at no cost to the proponent would be consistent with the NEO. Application of limits may also be perceived as reducing the risk of non-compliance if calculated limits are not achieved in practice. The interpretation

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	are operated historically in different parts of the network with respect to their PoC voltage and their reactive power generation before making a final rule determination. **AusNet – Supports** • AusNet supports the proposed Option 3 but notes the wording in the Draft Report may need further refinement before inclusion in the Rules (e.g., use of "a voltage band of ±5% normal voltage", as opposed to "10% voltage band around a centre-point …" Ideally the example diagram would be included, if permissible. **CEC – Supports, with further considerations** The reduced reactive power capability requirement at high and low voltages is generally welcome. However introducing a voltage 'centre point' that is determined by the NSP will only introduce uncertainty in the absence of a methodology to determine what this centre point is. Furthermore, if this centre point is not the normal voltage, then it would require primarily plant to be rated higher than +/- 10 % of the normal voltage (which is generally the nominal voltage). **CPSA – Supports, with further considerations (same as CEC)** • The reduced reactive power capability requirement at high and low voltages is generally welcome. However introducing a voltage 'centre point' that is determined by the NSP will only introduce uncertainty in the absence of a methodology to determine what this centre point is. Furthermore, if this centre point is not the normal voltage, then it would require primarily plant to be rated higher than +/- 10 % of the normal voltage (which is generally the nominal voltage). **Energy Queensland – Supports** • Ergon Energy and Energex support Option 3 over Option 2 and notes the preference that this requirement continues to apply to distribution connected generation, as noted in our response below on the issue of Simplifying Standards for small connections. **Goldwind Australia – Supports** • Goldwind supports both option 2 and option 3. • However, we would like AEMO to provide more clarification on whether option 3 offers any additional benefits, and consider choosing option 2 instead. Option 2 is easier to implement and evaluate, and would prevent investments in marginal cases. Additionally, since generators are typically in voltage droop control, it is unlikely they will operate when exporting reactive power during high voltage situations. **Hydro Tasmania – Partial support; issues raised** • HT is of the opinion that the 10% centre line should not be nominated by TNSP but should be +/-5% consistent with S5.2.5.13 (2B) (iii). If the TNSP is able to nominate the centre line conflicts may arise with this clause. Furthermore, it releases the possibility of the TNSP biasing the centre line prohibitive of achieving 0.395*Pmax, and thus negating the intent of this change. • The basis for this amendment is that a synchronous machine's limits for reactive power capability are fixed to plant design and not easily, if at all adjustable for existing units in so	of CUO under S5.2.5.4 and its interaction with this clause S5.2.5.1 may be a driver for application of limits on reactive power capability. AEMO will consider this in the drafting for the interpretation of CUO in S5.2.5.4. In the responses here and in S5.2.5.4 there have been references to the uncertainty created by use of normal voltage. As this term is only referenced in chapter 5, and has not been found in practice to be a useful concept, because having a normal voltage higher than nominal would impose additional costs for equipment that is generally designed to standard voltages. AEMO has therefore proposed to revert to nominal voltages where normal voltage is used in the technical requirements. **Revised recommendation** Considering the feedback, AEMO proposes to retain the Draft Report recommendation with the following clarifications: • Limit the mid-point voltage to a range that would not require operation above 110% or below 90%. • Reinforce that there is no need to limit to reactive power to levels defined by the AAS values by ensuring that the drafting says "at least" the amounts. • Revert rules that specify normal voltage to nominal voltage.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	meeting MAS or AAS is somewhat academic, i.e., whilst the proponent could maximise capability, the limits are ultimately fixed by import stability limits and export thermal field thermal constraints. • Furthermore, HT notes the proposal of a symmetric reactive capability requirement around a reference point does not reflect the main transformer reactive power consumption between the GS terminals and the connection point. As a result, the transformer reactive power consumption facilitates the GS leading reactive capability, but being a burden for lagging reactive capability, hence being challenging to be satisfied. • For greenfield applications compliance can be resolved during the preliminary applications process. • In summary, HT preference would be option 2 to simplify the connection application process and encourage capital expenditure for refurbishment or renewal in that the generator will not be subject to prohibitively uneconomical designs to achieve high capability that may not be required. HT supports option 3 only based on fixed +/-5% band from nominal connection point. **TasNetworks – Supports** • TasNetworks supports the proposed change. TasNetworks already allows a more pragmatic range in our local connection guideline. At the connection point the reactive power supply (export) range is 0.90 p.u to 1.07 p.u and reactive power absorption (import) range is 0.97 p.u to 1.1 p.u. **Tesla – Supports, with clarifications** • Tesla is supportive of the lower bands. We do, however, have concerns as to how NSPs nominate a voltage. We want to avoid a situation where NSPs have full flexibility in nominating their own voltage centre point. For transparency and consistency we would suggest that the 10% voltage band is centred around the “nominal voltage”, which is nominated by NSP as of the existing Rule. **Total Eren – Support** • Total Eren believe the current assessment practices and interpretation of S5.2.5.1 and S5.2.5.4 result in an inefficient outcome for new connecting renewable generators or established generators going through a 5.3.9 process. In our experience, the connecting Network Service Provider (NSP) is rarely willing to agree to negotiate a standard for S5.2.5.1, even when a conservative solar farm design is proposed (including a significant amount of apparent power headroom, even as high as 20% more MVA capacity than MW). The proposal presented by AEMO to amend the AAS and remove unrealistic operating conditions from the assessment is welcomed by Total Eren. **Transgrid – alternative proposed; issues raised** • Transgrid prefers that the existing AAS requirements remain in effect and that the negotiating framework is reinforced and potentially amended. Transgrid notes that it often relaxes the AAS in a similar manner if security allows this.	

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Transgrid suggests including Option 3 as a framework for the negotiated access standard, depending on the technical requirements at the connection point and plant limitations. Transgrid is also concerned that current NER wording encourages limits to reactive power to be enabled, and that the proposed approach may incentivise voltage dependent reactive power limits, which may reduce the post-fault voltage recovery, particularly if the plant is controlling voltage at an upstream bus, which is a commonly applied control strategy in Transgrid's network. That is, the full inherent capability of the generating system may not be made available. • Transgrid also considers that the centre point for the 10% range may need to change over the life of the plant as the operation of the system changes.	
Treatment of reactive power capability considering temperature derating	**AGL - Supports** • AGL does support this proposal and the desire to create consistency. On the requirement to reduce reactive power capability along with active power, AGL considers this should be a drafted so that a generator 'can' reduce reactive power capability along with active power but is not forced to. **Amp Power – Support – partial** • Amp Power generally support AEMO's recommendation. However, in our view the AAS should apply up to a certain temperature such as 35º C to ensure no unnecessary oversizing is required at very high temperature. **APD – Issues raised** • Considering inverters are typically configured in Q priority, implementation of a dynamic temperature dependent reactive power capability may require the Original Equipment Manufacturer (OEM) to implement temperature dependent reactive power limitations in the Power Plant Controller (PPC) in the case of a typical solar farm. This may prove more complicated than temperature-dependent active power which can be implemented through external SCADA that adjusts the active power setpoint based on ambient temperature. • APD recommends provision of case examples for various technology types to ensure a consistent assessment approach. **AusNet – Support** • AusNet supports AEMO's proposed Options 2 & 3. • AusNet would like to know if as part of this change AEMO would be capturing and hosting generator capability curve data files for different temperatures within OPDMS to aid with load flow studies. **CEC – Partial Support** • To the extent what is proposed is simply capturing what the plant can inherently deliver, this is not expected to be problematic. It isn't clear how this wording would provide any real value if this cannot be tested from a compliance perspective and/or is not considered in any planning and/or operational analysis undertaken by AEMO or the NSP.	Respondents were generally supportive of the proposed clarification regarding temperature derating, with some minor clarifications. AEMO does not agree with Amp Power that the AAS reactive requirements should only apply up to a particular operating temperature. The generator and network requirements for reactive power do not decrease with temperature. AEMO agrees that plant may have a maximum operating temperature, and this should be recorded in the GPS as part of this clause. AEMO agrees that the wording of the clause should not require a plant to have temperature dependent active and reactive power output. AEMO proposes to draft the rule such that it permits but does not require temperature derating. The documentation requirement can also be made subject to their being a temperature derating, in which case the default position is that if there is no documentation of a temperature derating, then the plant will be expected to maintain its reactive power capability and active power irrespective of temperature. Regarding Tesla's comment on other factors affecting the capability of a battery, AEMO suggests that these can potentially be documented as a negotiated access standard. OPDMS does have facilities to apply operation-related changes to models, where the relevant SCADA values are available. However, this is not within the scope of this project. AEMO understands that synchronous machines sometimes have temperature derating of active power. In such cases the reactive power requirement would also be applied to the maximum active power, considering the temperature derating, consistent with other generation. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation with the following revisions to: • permit but not require temperature derating

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Alternatively it could be captured in the PSDS. **CPSA – Partial Support** • To the extent what is proposed is simply capturing what the plant can inherently deliver, this is not expected to be problematic. It isn't clear how this wording would provide any real value if this cannot be tested from a compliance perspective and/or is not considered in any planning and/or operational analysis undertaken by AEMO or the NSP. **Energy Queensland – Support** • Ergon Energy and Energex have no objection to the suggested option. **EUAA** • EUAA recommends that reactive power temperature derating should be considered in terms of the actual conditions observed by the generation system and not defaulted to the manufacturers specifications for the ambient conditions on the day. For example, hydro generation located underground and inverter-based generation in an air-conditioned environment are not exposed to ambient temperature and thus derating on the basis of ambient temperature and manufacturer specifications is irrelevant. Using the irrelevant figures could trigger unnecessary market interventions creating unnecessary anxiety for consumers and reduces the consumers' confidence in AEMO's role as market operator. • For the purpose of market clarity, AEMO could consider exempting generators with climate-controlled environments from the requirement of providing derating data. **Goldwind Australia - Support** • We support Options 2 and 3. **Hydro Tasmania – issues raised** • HT has doubts on how temperature derating would be applied in practice for synchronous machines and if it is indeed necessary. • HT proposes option 1 should remain for synchronous machines where options 2 or 3 would create much unnecessary documentation, increase connection application inefficiencies and costs, and typically counter the objective of streamlining the connection process without adding any more value to the process. • HT is of the opinion consideration should be given to AEMO potentially providing some criteria for exceptions. • Considerations into this proposal are as follows: – In practice how will temperature derating be applied: would dynamic capability or temperature required to be transmitted to the TNSP / AEMO in real terms and/or capability diagrams created at various temperatures? – How would/should compliance be demonstrated at various temperatures, including requirements around accuracy?	• require documentation of derating only where there is derating • require that any maximum operating temperature be recorded.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	– Given also commissioned reactive capability may not be representative of maximum or minimum values, by applying further criteria the reactive capability may be restrictively offered to meet performance standards. • For synchronous machines the true temperature derating cannot be correctly known due to limitations in determining field winding temperature, and as commissioning and compliance testing is only ever performed at the maximum temperatures obtainable at that time (e.g. following a heat-run at current ambient temperature), the full range can never be entirely known. This is particularly true for Hydro and/or other air-cooled synchronous generators. **TasNetworks – Comment** • De-rating on high temperature is necessary with power electronics but it's critical that the maximum temperature is set appropriately. In Tasmania it would be unusual for multiple generators to be on currently exposed to ambient temperatures > 35 deg C but not so in many mainland jurisdictions. In particular, the maximum ambient temperatures defined for storage devices requires careful consideration. **Tesla** • As a point specific to a battery energy storage systems, derating is not necessarily a factor directly of temperature. It's related to a number of other factors. We are supportive of capturing the maximum operating temperature in the GPS. However we are not supportive of capturing derating for above the maximum operating temperature within the scope of the GPS. That should be an engineering discussion that considers the range of factors that influence derating of output above the maximum temperature range. **Transgrid** – Support • Transgrid supports Option 2 and Option 3 and clearly defining rated active power, maximum capacity and derated power.	
Compensation of reactive power when units are out of service	**AGL – Oppose** • AGL does not support a blanket obligation to require reactive power requirement when there is no active power coming from the generator. In experience with our wind farms, this requirement burns plant out and has implications for the overall life of the asset. Requiring this is seeking a power system service for free, when markets should be developed to pay for system needs. • Drafting should maintain optionality, as modes of operation that are a detrimental to wind and solar, can be provided by batteries. **Amp Power – Support** • Amp Power generally supports AEMO's recommendation. • The threshold should be set by the NSP and communicated at the connection enquiry or as soon as practicable to allow connection applicants to plan their systems. **AusNet – Support**	Most respondents support the proposal, but multiple variants have been proposed. AEMO considers that it is important to achieve a balanced approach that also assists with streamlining the connection process and supports efficient investment decisions consistent with the NEO. The present drafting refers to schedule 5.3, which describes a requirement in terms of power factor and voltage level of the connection. This doesn't make a great deal of sense for auxiliary and collector/balance of plant loads that have small active power and relatively larger reactive power components. The key factor determining whether there is an impact or not is the effect on voltage. Most respondents agreed that a voltage impact threshold was practical. Some respondents (NSPs) considered that the threshold should be set by the NSP. Compensation of reactive power from the connection is not a zero cost exercise, and typically increases either capital or operational costs of a connecting party. In principle, it is not the Generator's role to subsidise the operation of the network for its poor voltage regulation, nor should the

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• AusNet supports AEMO's proposed Options 2, 5 and 6, noting that option 5 should also include the ability to consider the switching of any reactive power plant within the generating systems to maintain the steady state voltage (e.g., removing partial or all harmonic filter plant from service during such periods) **CEC – Partial support, clarification and alternative option proposed** • The proposal for the voltage threshold associated with the reactive power range is subject to being able to come up with a suitable voltage threshold. This should be communicated at the connection enquiry stage to allow generators to plan for and design their generating systems. It might not be possible to come up with a consistent threshold across the NEM, thus impacting the feasibility of the approach. Alternatively, a limit which is a percentage of the reactive power capability can be defined which would provide more certainty to generators (eg limited to 5 % of the AAS under S5.2.5.1). **CPSA – Partial support, alternative option proposed (same as CEC)** • The proposal for the voltage threshold associated with the reactive power range is subject to being able to come up with a suitable voltage threshold. This should be communicated at the connection enquiry stage to allow generators to plan for and design their generating systems. It might not be possible to come up with a consistent threshold across the NEM, thus impacting the feasibility of the approach. Alternatively, a limit which is a percentage of the reactive power capability can be defined which would provide more certainty to generators (eg limited to 5 % of the AAS under S5.2.5.1). **Energy Queensland – Partial support, alternative option proposed; issues raised** • Networks must maintain compliance with the system standards as specified in Schedule 5.1 (and the relevant jurisdictional requirements) at all times. As such, whether the reactive power injection from ancillary plant is a material issue or not, in our view, it is for the Network Service Provider (NSP) to determine as the network is impacted daily (or regularly) due to the energisation/de-energisation of plant. Ergon Energy and Energex are supportive of the introduction of a material threshold. However, we believe that NSPs should have the responsibility of determining what the materiality for their network is, rather than an arbitrary value at a region or National Electricity Market (NEM) level. • Ergon Energy and Energex seek clarification on the use of 'limited compliance' in its Draft Report at page 35 in the last paragraph. A number of solar farms connected to the Ergon Energy and Energex network compensate for their harmonic filters at night with "Q at night mode", with the voltage control in this mode articulated by the voltage control strategy (VCS). We seek clarification whether the changed responses to S5.2.5.5 would also be articulated in this operating mode. **Hydro Tasmania – Support with clarifications** • HT supports option 2 and 6 based on streamlining the connection process. Where it is identified that the limits will not be met, HT supports option 5 to achieve minimal compliance burden but maintain flexibility in how this would be achieved once the Generator and NSP have agreed to this option.	connecting party be having an adverse impact on the network by its connection. AEMO considers that a reasonable impact threshold could be 0.5% change in voltage. If a fixed value is used, this should enable the connecting party to build the requirement into its design and procurement decisions most efficiently. The voltage impact will be influenced by the short circuit level of the power system. A very high short circuit level will lead to a high sensitivity of reactive power to voltage. Likewise a low X/R ratio would increase the sensitivity of voltage to active power. Considering this and some of the respondents' comments about the value of up-front information, AEMO considers that the typical value of system impedance level used for S5.2.5.13 could also be used here. AEMO considers it would be unreasonable for the plant to be required to change its design or operation for level of reactive compensation over the life of the plant if there is no change to the connection. We do not propose to put anything in the rule that would require this. AGL was the only respondent who opposed this change on the basis that on wind farms it "burns plant out". The proposed rule does not limit the mechanisms by which the voltage impact can be mitigated and absence of the change would not avoid the need for some level of compensation. The main consideration in this proposal around operation of units in reactive-only mode is to recognise that (if this mechanism is chosen) with a small number of units in service to provide reactive compensation only, there should be less concern about the dynamics of the small proportion of the plant in service, because it is highly unlikely to impact power system security, in which case a lower set of compliance assessments is appropriate. AEMO agrees with Transgrid that there are two aspects of zero output that could be considered – one in which the production units are not in service, and the other in which the production units are in service but not producing. The intent of this change is to deal with the first of these, with the expectation that the second one should be managed through the main part of NER S5.2.5.1 (with a negotiated access standard if necessary). Regarding the ride-through requirements of other clauses as applied to units providing reactive compensation for auxiliary load/balance of plant only, AEMO considers that units used for these purposes need not remain in operation for contingencies described under NER S5.2.5.5, or under- or overvoltage conditions described under S5.2.5.4, but power quality requirement should still apply at the connection point. If the units tripped during contingencies and remained out of service this would constitute a non-compliance with this clause, unless operational arrangements were agreed around reconnecting them.

<table>
<tr><th>Issue</th><th>Schedule 5.2 Generator recommendation feedback summary</th><th>Consideration of issues and revised recommendations</th></tr>
<tr><td></td><td>Transgrid – Support with clarifications
In Transgrid's view, there are two distinct aspects relating to plant performance and reactive power supply/absorption when not generating active power, and must be looked at separately for clarity.
a) When all generating units are disconnected from the power system – this is covered under S5.2.5.1(g) where at present the performance standard is established under clause S5.3.5.
b) When generating units are connected to the power system while not generating active power – the generating system will be required to have sufficient reactive power capability to compensate for the reactive power supply/absorption of the plant (aux load, reticulation network and harmonic filters), such that the net impact on the system voltage due to the plant at the connection point is minimal.
Regarding Option 2, when allowing such exemptions, careful consideration must be given considering the cumulative adverse impact on the network over a period of time when multiple generators are connected in close proximity.
Transgrid supports Option 5 - where the NSP requires that the steady state reactive power levels are to be maintained within the required range, this can be treated as a secondary operating mode.
Transgrid supports Option 6 - the maximum active power consumption in respect of auxiliary load and the corresponding reactive power range permitted at the connection point, to be documented.</td><td>AEMO agrees with Transgrid that there are potentially cumulative impacts of multiple generating systems connecting. However, considering efficiencies of scale and the proposed low voltage change threshold, it will represent more efficient investment in the NEM for the Network Service Provider to install a single static reactive device at an appropriate location (capacitor or reactor) than to require additional compensation from every generating system in the vicinity.
Revised recommendation
Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendations with the following clarifications:
specify that the NSP provides the typical system impedance during connection enquiry response [also used for S5.2.5.13]
apply a fixed threshold of [0.5%] change in voltage for the need for compensation.
not mandate that units are left online to provide reactive compensation; however if that solution is selected to require that the performance compliance requirements and assessments require a settling time for a voltage step of up to 5% at the connection point, consistent with the S5.2.5.13 requirements for the relevant control mode.
no other performance standards except S5.2.5.2 are to apply for operation in this mode, provided it is a primary or secondary control mode for the relevant plant in normal operation.
Note
In the drafting and here AEMO has shown the 0.5% in brackets and requests specific feedback on this number. The threshold provides a balance between provision of reactive compensation centrally by an NSP and provision by multiple connecting parties individually. Either way there will be costs borne by the consumer that are reflected in the price of electricity. The challenge is to set a threshold that achieves the overall minimum cost to consumers consistent with the NEO.</td></tr>
<tr><td colspan="3">S5.2.5.1, S5.2.5.5, S5.2.5.7, S5.2.5.8, S5.2.5.10</td></tr>
<tr><td>Simplifying standards for small connections</td><td>APD – issue raised (clarification)
For S5.2.5.5, the proposed change states that the technical assessment could omit reactive current injection requirements. Since this is not proposed to be an AEMO advisory matter, it is implied that the performance standard will still need to be negotiated with the NSP. From the proposed wording it is unclear whether assessments of positive to negative sequence reactive current would be required. This should be clarified to reduce the risk of required reassessments during project due diligence.</td><td>The responses to these proposals were varied across the different clauses and these are considered separately below.
S5.2.5.1
The proposal to reduce the AAS for S5.2.5.1 for small systems less than 30 MW was universally opposed by NSP respondents, for various reasons. Reasons included that there are already pragmatic relaxations proposed for S5.2.5.1 generally, 30 MW is too large a threshold for some regions. Energy Queensland also indicated that it wasn't appropriate to apply the proposal to</td></tr>
</table>

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Setting Qmin/Qmax based on the reactive power for 5 % voltage change at POC for distribution connection has the following ambiguities: – 5 % voltage change is a function of POC Fault Level (FL, grid impedance) and hence the assessment FL also need to be specified by the NSPs. – How to categorise distribution or transmission connections? For example, in TAS, 110 kV is defined as transmission connection whereas in many parts of mainland 132 kV connections are considered as distribution connections. Hence the voltage levels of distribution connection need to be defined. **Ausnet – Opposes change to S5.2.5.1** • AusNet does not support the relaxation of the AAS of S5.2.5.1 for generators less than 30 MW. There are circumstances where full reactive capability for smaller generator is desirable in the distribution network. There is always the option to negotiate in circumstances where this is not possible for the generator, and there are already pragmatic reductions to the S5.2.5.1 AAS considered in this review. **Ausnet – Supports not changing S5.2.5.3** • AusNet supports AEMO's proposal to do nothing. **Ausnet – Opposes the proposed change to S5.2.5.5; alternative option proposed** • AusNet does not support AEMO's proposal as written but agrees there may be some pragmatic changes to consider for smaller plant. Optimization of reactive current injection distribution-connected generators is critical to maintain the resilience of the distribution network, therefore IGBT blocking during faults should not be allowed. A general exemption of reactive current injection requirements will encourage inverter based generating systems to block the current injection controls during disturbances, which AusNet cannot agree with. However, the quantity of current injection, location of assessment, reactive current rise time, post fault active power recovery time and MFRT requirements could be relaxed for generators less than 30 MW, and a bottom-up approach to the negotiation framework may be suitable. The main objective for distribution-connected generators is to optimize post-fault voltage stability. To achieve this, it may be acceptable to reduce the current injection gradient (K factor), increase the rise time to improve the post-fault voltage stability (as a rule, we expect the rise time to be less than one third of the fault clearance time). Similarly, extending the duration of post-fault active power recovery may improve the overall stability of the control system, and can be considered if necessary. MRFT requirements under AAS (15 faults in 5 mins) are extremely unlikely in the distribution network, and therefore, the AAS should not be mandated for distribution network connected projects. **AusNet – Supports the proposed change to S5.2.5.7** • AusNet supports AEMO's proposal. **AusNet – Supports the proposed change to S5.2.5.8** • AusNet supports AEMO's proposal.	large generators connected to the distribution network (citing 150 MW plant). Transgrid suggests that it could be difficult to apply a 5% step change criterion to establish the limits, and proposes either reducing the range of reactive power requirement or just the voltage-dependent reactive requirement described for S5.2.5.1. Most connecting parties supported the change. One respondent suggested alternative limits, but without justification. Considering that there is a lack of consensus on this matter, AEMO proposes not to proceed with the change at this time. **S5.2.5.3** AEMO proposed not to change S5.2.5.3, and most respondents either did not comment or agreed with not making any change. **S5.2.5.5** For S5.2.5.5 AEMO proposed to exempt small generators from the need to demonstrate a performance standard for reactive current injection. This was considering that the requirements otherwise to remain in CUO would continue to apply, and for low X/R ratio, the voltage is impacted by active current injection to a greater extent than for the high X/R conditions typically experienced by large generators connected to the transmission network. AusNet suggested this might incentivise inverter blocking during faults, which they oppose, but suggest that other aspects of fault response could be relaxed, with the focus being put on post-fault voltage stability. AEMO agrees that generally blocking of output during a fault is not a desirable behaviour. Energy Queensland argues that not specifying a requirement to negotiate reactive current injection means that the performance of the power system would be worse. AEMO does not agree that this is necessarily the case, as the generator would need to provide reactive current injection to support its ability to remain in CUO during faults (noting the discussion about not blocking, above). Energy Queensland further argued that the proposed changes would conflict with the recent changes made by the AEMC to S5.2.5.5. Hydro Tasmania and TasNetworks are concerned about the 30 MW threshold, relative to the size of the power system and the potential for cumulative impact. EUAA also discusses the effect that thresholds have on investor decisions. The fact that a threshold can impact the size of investments clearly indicates that the complexity, cost and resource requirements of the connection process is significant, especially for small scale projects.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	AusNet – Seeks clarification on the proposal to exclude connections less than 30 MW from AEMO advisory matters • If the technical standards for generators or GPS are mutually agreed upon by the hosting NSP and the Sub 30 MW generators/load, does this imply that connections with generation or load below 30 MW will be exempted from technical requirements during the NEM application process, knowing that each connection's requirement is up to the relevant Distribution Network Service Provider's discretion? • What is the process for managing generators that want to participate in the AGC and FCAS markets? • In the case of a generator seeking to upgrade their system through the 5.3.9 process, what happens if there is no PSMG compliant models as a result of relaxed connection requirements from relevant Distribution Network Service Provider? **Bo Yin – Alternative option proposed** • As the amount of reactive power needed to regulate voltage to certain level depends on V-Q sensitivity at the regulation point, why reactive power capability of 0.395 pu instead of 0.329 pu [reference to UK grid code] should be required? How the amount of reactive power has been determined? • High inductive Q is needed at high voltage and high capacitive Q is needed at low voltage for voltage regulation. Therefore, UQ profile similar to GB grid code is more preferable. • The Q capability defined in 5.2.5.1 is static reactive capacity obtained with the help of OLTC and MSC which might not be able to fully utilized in 5.2.5.13. So there should be no direct link between voltage droop setting and voltage range for full reactive power requirement in 5.2.5.1. **Energy Queensland – Strongly opposes proposed change to S5.2.5.1** • Ergon Energy and Energex are strongly opposed to the proposed for changes to S5.2.5.1 for small connections. • In our view, applying the proposed changes to all connections in the distribution network is inappropriate. The largest generator connected to Ergon Energy's network is 180MW which is larger than some transmission connected generating systems. Having inconsistent access standards based on which network the system is connecting to rather than any technical basis, is not suitable in our opinion. Further, the Draft Report states 'This considers that reactive power that leads to large changes in voltage on the distribution network is probably not usable, as the distribution network is usually operated to tighter voltage tolerances than the transmission network.'[1] This statement ignores that reactive power is 'used' locally. If the network is sensitive to changes in reactive power, it will also be sensitive to changes of active power, that is, the injection of active power caused by the generating system needs to be managed with commensurate reactive power. It is vital that	Considering that a number of NSPs see value in being able to negotiate on reactive current injection performance even for small plant, AEMO does not intend to progress this change. **S5.2.5.7** For the proposed change to S5.2.5.7 to exempt generators and IRS less than 30 MW from assessment under this rule, most respondents supported the change. Transgrid sees nothing wrong with the present requirements for S5.2.5.7. However, AEMO is not considering whether there is anything "wrong" with them, rather whether there is net benefit in omitting them for small connections, to improve efficiency of the connection process, considering that requiring compliance assessment for any level of performance takes resource. **S5.2.5.8** AEMO proposed to harmonise the requirements for this clause to plant 30 MW or more, regardless of technology. Most responses on this proposed change were positive, except that TasNetworks and Hydro Tasmania considered that the 30 MW threshold might be too high in Tasmania. AEMO proposes to retain the Draft Report recommendation. Additional commentary on the size threshold is provided below. AEMO has redrafted this clause as AAS and MAS, for other issues. Considering that plant larger than 30MW can be connected in a distribution network, AEMO has made the requirement for overfrequency generation reduction apply to distribution as well as transmission-connected plant. **S5.2.5.13** Similar to the issue described in S5.2.5.7, AEMO has also identified a similar unnecessary technology-specific threshold distinction in the MAS of S5.2.5.13, which we propose to remove. The thresholds relate to excitation ceiling voltage, settling time and over and under excitation limiters for synchronous plant, and settling time and limiting devices for asynchronous plant. At present there is a lower limit for bidirectional units of 5 MW. AEMO proposes to change this threshold to make it 30 MW. This issue was not specifically identified in the draft report. **AEMO advisory matter threshold to all technical requirements** In the definition of AEMO Advisory Matters, AEMO proposes to exclude connections less than 30 MW.

[1] Table 9, page 38.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	generators connecting the distribution network are appropriately able to control the voltage at their connection point in order to maintain acceptable power quality for all network users. **Energy Queensland – Opposes proposed change S5.2.5.5** • The reasoning behind the relaxation of requirements for S5.2.5.5 in terms of reactive current injection appears short sighted. While there may be minimal impact at a system level, the generating system will help to improve recovery in the local network it is connected to. A reduction to 'nil', means that the generating system will worsen the performance of the network during a fault, and worsen fault recovery for network users in the area. If generating systems are not required to articulate a response, or provide any evidence towards this, this effectively reduces the standard. Given that it is anticipated that generating systems will be less centralised in future, it is suggested that every small generating system contributing will improve network resilience. Similarly, given that micro embedded generating units have increasing performance requirements for fault-ride through and -recovery behaviour, it seems incongruous to remove this requirement for larger systems that are more suited to be properly tuned and exhibit controlled responses during a fault. The Draft Report states that the proposed changes to the automatic standard do not contradict the review of the MAS under the Efficient Reactive Current Access Standards for Inverter-based Resources (ERC0272) rule change. However, by removing compliance or evidence requirements for current injection obligations, we suggest that this is in conflict with the review. **Energy Queensland – AEMO Advisory matter - Issues raised** • In terms of AEMO advisory matters, aside from technical due diligence, a key role for AEMO is to ensure consistency and clarity across the NEM for connections. It is unclear to Ergon Energy and Energex how consistency and clarity will be achieved without AEMO's involvement for these connections. For example, NSPs do not have the required system-level insight to determine whether a proposed negotiated access standard for S5.2.5.11 is appropriate. Should there be a preference to reduce oversight for connections under 30W, AEMO still has the ability to determine the amount of due diligence and review conducted as part of the connection process, without a blanket removal of AEMO advisory matters. • Ergon Energy and Energex also question whether AEMO will no longer consult with NSPs on matters of system strength related to clause 5.3.4B for systems less than 30MW, given that this advice is largely based on response to performance standards (for example S5.2.5.5). **EUAA – Supports in principle** • The EUAA supports simplifying the connection process for small generator connections up to 30MW. The EUAA is aware of some developers avoiding the complicated connections process for generators less than 30MW by splitting installations into many 4.9MW facilities, which do not require network modelling and do not meet the NER's monitoring and control requirements. EUAA anticipates that by simplifying the connection process for generators less than 30MW, a market signal will be sent to the sub 5MW developers to create larger installations. However, care must be taken to ensure that developers do not split facilities	**Tasmanian threshold** TasNetworks requested a definition of small based on the size of the region, and Hydro Tasmania also provided similar comments. Tasmania is smaller than other regions and not interconnected to the main network through an AC interconnector. As most of Tasmania's generators are small, the effect of this clause might be different compared with other regions. There is precedent for different frequency standards in Tasmania (considering the Frequency Operating Standards, and their translation into S5.2.5.3). **Revised recommendation** Considering stakeholder feedback, AEMO proposes: • S5.2.5.1 – to not progress the Draft Report recommendation. • S5.2.5.5 – to not progress the Draft Report recommendation • S5.2.5.7 – to retain the Draft Report recommendation . • S5.2.5.8 – to retain the Draft Report recommendation • S5.2.5.13 – to make size threshold for bi-directional units equivalent to other plant for the application of some MAS clauses. To implement a different threshold in Tasmania, considering the small size of its power system relative to the mainland system, AEMO proposes to define in applicable clauses a term 'relevant system', which sets the threshold as the lower of 30 MW (or 30 MVA as applicable) or the amount in MW or MVA that is 5% of any maximum credible contingency event size (in MW or MVA as applicable) specified in the frequency operating standard for the relevant region. This would result in a 7 MW threshold in Tasmania, considering that the maximum credible contingency event size is 144 MW. The maximum credible contingency event has been specified in consideration of the small power system size in Tasmania and because it is coupled to the rest of the power system by a DC link. There is no maximum contingency event size specified for mainland regions.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	larger than 30MW to meet the proposed simplified connections process for sub-30MW facilities. **Hydro Tasmania – Supports in principle; alternative options proposed** • HT supports simplifying standards for small connections but also highlights the risk of cumulative small connections presenting a power system security issue for smaller regions (e.g., Tasmania) or intra-regional locations with low system strength. • [30MW] seems somewhat of an arbitrary number and HT believes consideration should be given to either be a proportion of the regional generation capability, or possibly better a value proposed by AEMO / TNSP based on regional operational risks and constraints with agreement from regional participant. HT acknowledges that whilst this approach may result in different "MW-thresholds" within the NEM it may also be a technically sounder approach. • HT also raises the potential to exploit this rule e.g., for non-synchronous or inverter-based generation comprised of multiple smaller generators feeding into a common connection point which is maintained below 30MW. This would then place the burden on the remainder of the base-load generation, i.e., if a 'small' generator is not adequately defined it could detract from future investment to large scale generators whereby multiple 'smaller' generators present a more attractive investment case, with reduced technical requirements (also goes toward cumulative small connections risk). • HT believes consideration should be given to perhaps a better solution of defining small, medium and large generators with small being entirely exempt, medium needing to satisfy only the MAS for AAS, and large following normal connection requirements. But with each definition based on regional requirements. • HT notes that CUO relaxation also increases cumulative risk. There is scope to relax this to a more practical level and simplify the connection process, but the intent to ensure CUO through credible event should be maintained. Without this it is inevitable a power system security risk will result. **Hydro Tasmania – Supports the proposed change to S5.2.5.1** • No Issue **Hydro Tasmania (Alternative proposed) for S5.2.5.3** • Supports relaxation of any requirement for small generators once a regional based definition is established to ensure the stability of the network for frequency excursions prior to any relaxations. **Hydro Tasmania – Supports with clarifications proposed change for S5.2.5.5** • Supports relaxation of any requirement for small generators once a regionally based definition is established. **Hydro Tasmania – Supports with clarifications proposed change for S5.2.5.7** • Supports relaxation of any requirement for small generators once a regionally based definition is established.	

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	TasNetworks – Supports with clarifications • TasNetworks supports the concept of simplifying standards when the connection party will have limited impact on the network. However, the definition of 'small' is relative. In Tasmania generators >5 MW can have an impact on the network. Currently TasNetworks works with AEMO to determine whether a connection should be exempt from being a scheduled connection and this form of process should be available in networks where small is not <30 MW. **Tesla – Support** • Tesla supports these recommendations. We're likely to see a number of smaller connections driven by community storage tenders and other projects. This will simplify the connection process. **Transgrid – S5.2.5.1 Oppose; Alternative proposed** • Transgrid recommends either using the current framework and reduce the AAS requirement or adopt one or more of the proposals presented under Section 3.2.1 (for example, option 2) [this is the proposed option for the voltage-dependent reactive power requirement discussed in S5.2.5.1 above]. The cumulative effect of multiple generators and system strength can make it difficult to quantify the 5% voltage step change requirement proposed (or other magnitude). **Transgrid – S5.2.5.3 Support** • TransGrid supports the proposal to do nothing. **Transgrid – S5.2.5.5 Oppose; alternative proposed** • Transgrid does not support exempting generating systems < 30 MW from all assessments related to current injection. Rather, Transgrid recommends exempting small generating systems from the AAS. Thus, only establishing a MAS for these generating systems. This would still encourage these smaller generating systems to provide dynamic voltage support to the network using their latent capability but would also reduce the negotiating process to establishing the performance standards. **Transgrid – S5.2.5.7 Oppose** • Transgrid does not consider there to be any issue with the current rule, even for small connections. Transgrid proposes to do nothing. **Transgrid – S5.2.5.8 Supports** • TransGrid supports option 6 - Apply the same size threshold irrespective of size of plant – 30 MW.	
NER S5.2.5.2 – Quality of electricity generated		
Reference to plant standard	**AGL – Support** • AGL supports the proposed amendment. **APD –Supports**	There was general support for this change, and AEMO proposes to include it in the proposed drafting.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• APD supports the correction/removal of reference to any superseded standards. From APD's experience, different NSPs have different methodology and calculation methods for assessing this schedule. To make the assessment uniform across the NEM, it would be beneficial for AEMO or combined NSP forum to produce a set of guidelines on the harmonic assessment methodology. **Goldwind Australia - Support** • Goldwind supports option 2. **Hydro Tasmania – Support with clarification** • HT supports option 2 in principle of maintaining alignment to the current version of the standards as at time of registration for new generators or for upgrade of components to new. • However, HT believes allowance should be made that a generator must only comply with the standards noted in the version of the NER as at original commissioning for an existing generator, and where generator manufacture pre-dates NER exceptions should be allowed. **TasNetworks – Support** • TasNetworks supports the removal of superseded standards. **Tesla – Support** • Tesla is supportive in principle of this change. **Total Eren – Support** • Total Eren views the proposals to amend S5.2.5.2 as relatively non-contentious and progressed quickly as incremental rule changes. **Transgrid - Support** • Transgrid supports the proposal to remove reference to the superseded standard.	Hydro Tasmania makes a further suggestion that a generator should only be required to comply with the standard that existed at the time that performance standards were agreed. AEMO agrees this is generally understood practice. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.
NER S5.2.5.4 – Generating system response to voltage disturbances		
Overvoltage requirements for medium voltage and lower connections	**AGL – Support** • AGL supports the proposed amendment. **APD – Support** • APD agree with the AEMO recommendation to more clearly define overvoltage requirements. **AusNet – Partial Support** • AusNet opposes proposed option 2 [Amend the AAS to make the point of application of overvoltages the nearest HV transmission location, for MV connections not through a transformer with onload tap changer.] AusNet agrees that it would add additional complexity when assessing a connection, which should be avoided. That is, how to accurately determine the contributions of multiple generators or IRPs from downstream MV/LV level connections to the voltage profile at the HV point and assess the potential impacts from its	Respondents, with the exception of AusNet supported the proposed change of location for the assessment of overvoltage conditions. Energy Queensland questioned whether studies have been done to demonstrate that high voltages could not occur on the sub-transmission network. The question is rather whether it is reasonable to require a generating system to ride through a 115% for 20 minutes or 120% for 20s on the sub-transmission or distribution network. It seems unlikely that Energex or Ergon Energy operate their systems in such a way as for this to occur in practice. As explained in previous descriptions of this issue, the background to this clause is related to transmission level voltages where overvoltages may not be able to be reduced through transformer action, and large amounts of generation may be impacted, with consequence for power system security. The impact on the

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	individual source if moving the Point of Connection (PoC) to the nearest HV side for all the downstream connections. • AusNet supports proposed option 3 [Relax the condition on negotiation of a lower standard than AAS (NER S5.2.5.4(c)) from a combined loss of 100 MW to loss of production of combined size consistent with the large single production unit contingency size in the region.] **Energy Queensland – issues raised** • The Draft Report notes, the purpose behind this clause is to target power system resilience. Ergon Energy and Energex seeks clarification whether studies have been conducted to demonstrate that high voltages are non-credible in the subtransmission or distribution networks. **Goldwind Australia** - **Support** • Goldwind support Options 2 and 3. **Hydro Tasmania – Partially supports, with additional issues raised** • HT notes that this rule omits any consideration to flux capabilities of generators and supply transformers. In the case of supply transformers with online tapchangers, generator over-fluxing can be managed as secondary regulation. However, in the case of fixed or offline taps, protection of the generator must be allowed for in the connection application for existing generators. • Furthermore, HT would like to highlight that by taking the (existing) maximum over-voltage and considering it to occur with (minimum) under-frequency, it is proposed that no current or future synchronous generator would be capable of CUO, and that no new synchronous machine specification would, or does allow for this due to the uneconomical specification that would result. Enforcing a rule that cannot be met without potential damage to a generator would disincentivise capital investment to modernise plant that would trigger connection application process. • In summary as a general comment, HT is of the opinion that the interpretation and compliance of over-voltage, under-frequency and over-fluxing should be more clearly defined to streamline the application process. • HT otherwise supports option 3 with the additional comment that provision should be allowed for MAS that requires only agreement with the TNSP. **TasNetworks – Support** • TasNetworks supports this recommendation. **Tesla – Support** • Tesla is supportive of this change. **Transgrid – Supports option 2, opposes option 3** • Transgrid supports the proposal to move the overvoltage location to the nearest HV transmission location, for MV connections without an onload tap changing transformer.	distribution or subtransmission would be less, and the amount of affected generation also less. In regard to Option 3, which changes the size limits on negotiation under this clause S5.2.5.4. Respondents other than Transgrid supported this proposal. Transgrid considers that expanding the size limit would reduce the requirement to negotiate under S5.2.5.4. AEMO disagrees with this statement. The existing clause gives the NSP and AEMO a right of refusal for negotiation. The NSP and AEMO have the right of refusal on the grounds of power system security and quality of supply impacts in any case, under the negotiation framework. Additionally, the negotiation framework already requires the proponent to justify why they cannot meet the AAS. Considering these two factors it seems unnecessary to have another right of refusal which is not specifically tied to security or quality of supply impacts. In addition, the MAS is much higher now than when that limitation was originally written in the 2007 rules. On further consideration of this reasoning AEMO proposes to omit the size limit on negotiation, altogether. Hydro Tasmania raises a different issue, related to overfluxing of transformers and generators, particularly for a combination of extreme underfrequency and overvoltages. AEMO agrees that a combination of overvoltages and underfrequency simultaneously could lead to over-fluxing protection (V/f) operation. The timeframes for frequency and voltage events are typically quite different, with frequency events typically much longer duration. However, it would be technically possible, although rare, for an overvoltage event to occur during a frequency event. S5.2.5.8 (a)(1) requires that protection not disconnect the plant for conditions under which it must remain in CUO for another clause. This means that technically a plant must be able to remain in CUO for combinations of abnormal voltage and frequency within the levels and durations of S5.2.5.3 and S5.2.5.4 if they occur simultaneously. Simultaneous overvoltage and underfrequency events, because of the timeframes, are likely to arise from different contingency events. It would therefore be possible to declare a specific limitation under which these occur in S5.2.5.5 under the multiple contingency clause. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to revise the Draft Report recommendation, to: • remove the limit on negotiation based on size of plant, altogether.

<table>
<tr><th>Issue</th><th>Schedule 5.2 Generator recommendation feedback summary</th><th>Consideration of issues and revised recommendations</th></tr>
<tr><td></td><td>Transgrid prefers to retain the existing S5.2.5.4(c) requirement and negotiate this clause as appropriate on case-by-case basis, if necessary. We also note that giving effect to Option 2 will also reduce the requirement to negotiate clause S5.2.5.4.</td><td></td></tr>
<tr><td>Requirements for overvoltages above 130%</td><td>AGL
AGL supports option 5+6: Substitute subclause for a requirement to design for switching surges “slow front overvoltages” defined in IEC 60071.1 2019 and specifically allow short-term (<20ms) blocking to protect units.
Also include an upper boundary for duration limit of 20 ms.
Amp Power
Amp Power would welcome the inclusion of an upper limit for voltages greater than 130%.
APD
We agree with the AEMO recommendation to more clearly define overvoltage requirements.
AusNet
Of the options put forward, AusNet supports Option 8 (2+4+6), with the following notes:
Sub-option 2: AusNet agrees that there should be greater scope to negotiate where the AAS may be overly onerous or unreasonable for a given point in the network. This is especially relevant in distribution networks.
Sub-option 4: While AusNet agrees that greater clarity should be given in the form of either a ceiling (option 4) or a floor (option 3), given the commentary AEMO provided on page 43 regarding the source of >130% TOV, is there a possibility that there has been a conflation of ideas between voltage impulse withstand levels (i.e., a negotiable matter under S5.2.3) and power frequency voltage matters (i.e., S5.2.5.4 and S5.1a.4)? Should such short-term impulses really be considered in a standard which is operating within the umbrella of power frequency (i.e., 50 Hz)? If so, perhaps consideration should be given to clearer requirements under S5.2.3 instead, and the proposed simple modification added to the AAS in S5.2.5.4 as described in Option 3 (i.e., CUO for at least 130% TOV).
Sub-option 6: While AusNet agrees in principle, there may be challenges in correctly wording the short-term blocking allowance given that the overvoltage would be at the point of connection but the decision to block would need to be made on a unit-by-unit basis at its terminals (i.e., what is the TOV that each unit needs to meet for such a connection point TOV? And how is compliance assessed? Should standards include voltage at unit terminals?) Generally: AusNet agrees that there are nuances and difficulties in correctly implementing this clause and would be willing participants in any further discussions.
CEC
The CEC welcomes inclusion of an upper limit for voltages greater than 130 %.</td><td>AEMO did not recommend a proposed option for this clause, but sought feedback, noting that the current wording results in an unbounded over-voltage requirement, which is not a manageable risk for a connecting party.
At the workshop on this issue, the most favoured option was to change the wording to “at least 130%”. However, there are potentially conditions within the network under which switching surges above this level can occur. As noted in the Draft Report, lightning flashes may result in higher voltages, but it is switching surges that are of most concern.
AEMO considers that if switching surges occur for a particular network configuration which cause the voltage to exceed 184% peak, the source of the overvoltages should be addressed, to mitigate the problem.
Note: peak voltage of 130% rms is 183.8%. The selected peak voltage coordinates with NER S5.2.5.4(a)(2) which refers to voltages up to 130%.
As noted in the Draft Report, protection against surges is typically managed by means of surge arresters and the plant should practice good engineering practice in the design of such systems.
Arresters designed for surges should also protect for lightning (fast front overvoltage) for voltages exceeding the specified peak voltage. It is impractical to measure compliance for fast front overvoltages so there is no value in specifying a separate number.
It is consistent with a resilient power system that generation be well-protected against transient overvoltages whether these are a result of lightning or switching surges.
AEMO would expect that a plant should be able to remain in operation for a switching surge of greater than the 184% peak, with a waveshape of the type described in IEC 60071.1.
The proponent should be able to demonstrate this with their selection of surge arresters.
However, it would be unreasonable to expect a plant to withstand switching surges at such high voltages repeatedly.
If switching surges occur repeatedly, it would be prudent to investigate the source of the surge and for the NSP, or if within the connection, the connecting party to take measures to prevent further occurrences. If switching surges persist, they will cause deterioration of the protective devices over time, which may damage the plant.</td></tr>
</table>

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Guidance by international standards such as IEC 60071.1, as proposed in Option 5, may allow for easier coordination within a context of global equipment sourcing, where there is significant dependence upon IEC and other international standards. **EUAA** • The EUAA agrees that none of the proposed options fully cover the different causes of overvoltage above 130%. The EUAA considers that where a generator is exposed to overvoltage above 130%, and this is caused by: – network infrastructure: the NSP should be the participant that investigates and remediates the cause; – the generator: the generator should investigate and remediate the cause, and – a juxtaposition of generators and/or network infrastructure then AEMO should investigate and determine the cause and direct the remediation to the appropriate participant(s). • The EUAA recommends that more work and discussions are needed before a rule or rules are drafted for consideration to define these separate events separately, and not under one definition. The EUAA considers this as each cause for overvoltage has quite different causes and participants responsible. By separately defining each event the responsible participant and action required will be clear. **Goldwind Australia** • Goldwind support Option 3. [change to "at least" 130%] • Regarding option 4 [defining an upper limit]: – Which factors influence the upper threshold? Identifying the appropriate upper limit may necessitate a thorough analysis to establish a suitable limit that caters to the majority of industry applications, without showing favouritism towards any particular technology. **Hydro Tasmania** • HT supports option 3 [change to "at least" 130%], this would provide the simplest solution but requests further consultation. It should also consider worst-case under-frequency such that over-fluxing protection is also bound. **TasNetworks** • There is a difference between temporary over-voltages (TOV) and transient over-voltages. • It is not practical to "control" network transient over-voltages with very short time frames. They must be limited with passive devices. The TOV curve is deliberately silent on over-voltages below 0.02s because the TOV curve applies to root mean squared (RMS) quantities, which are not defined in sub-cycle time-frames. Lightning strikes and other short-term transients can cause very high voltage "spikes" at the point of connection. It is infeasible to prevent these voltage spikes and it should be clear that system disconnection (trip), which takes 2-3 cycles, does not offer overvoltage protection against such transients. However, with appropriately sized surge arresters, spark gaps etc. the risk to equipment can be acceptably reduced.	Currently there does not appear to be any clause within Schedule 5.1 that places an obligation on NSPs to manage switching surges that cause overvoltages outside of the system standards. There has also been some support for allowing plant to block to protect itself for voltages above 130% rms or above 184% peak, for short duration associated with a lightning flash or switching surge. To be consistent with the proposed commencement time of 10 ms for reactive current injection/absorption under S5.2.5.5, AEMO proposes to allow blocking for up to 10 ms in S5.2.5.4. **Recommendation** Considering stakeholder feedback, AEMO proposes to: • Amend the NER S5.2.5.4 (a)(1) to require continuous uninterrupted operation for peak voltages greater than 184% (with reference to IEC 60071.1 waveforms • Apply an obligation on NSPs under S5.1.4(a1) to design its network and insulation coordination so that switching of network elements does not expose a Network User's plant to switching surges for voltages above those described in the system standards. Noting that this element of the solution was not workshopped, AEMO seeks specific feedback from NSPs on the implications of this recommendation for them. • Amend NER 5.7.2 so that a Registered Participant whose plant is affected by surges can request the NSP to undertake an assessment of the cause. • Permit the plant to block for transient overvoltages that exceed 184% peak voltage at the connection point for less than 10 ms. • Clarify that for the voltages described in S5.2.5.4 (a) (2) to (8) and (b)(1) to (5) are power frequency root mean square voltages and the voltage described in S5.2.5.4(a)(1) refers to voltage waveforms described in IEC 60071.1. AEMO would welcome additional feedback on this recommendation and the associated draft NER amendments.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Network users are obligated to protect their own equipment. Unless the transient over-voltage is due to a fault on the circuit connecting the plant to the rest of the network the plant should ride through. In case of a fault on this local circuit, other protections will trip. This approach aligns with the basic principle of protection discrimination and must be retained. • It may be acceptable to allow a temporary insulated gate bipolar transistor (IGBT) block (approximately 0.02 s) since, although blocking will not protect the inverter from over-voltage, it could help ameliorate any consequential over-currents. The CUO (CUO) definition could be amended to allow such a short-term interruptions, e.g.1-2 cycles. **Tesla** • Tesla would suggest an alternative that could be considered is to delete S5.2.5.4(a)(1) which would effectively create an upper bound of 130%. • Alternatively we would be supportive of Option 4 which would see the introduction of an upper-voltage limit of 140%. **Transgrid** • In Transgrid's view, the current rule requirement for "over 130% of normal voltage for a period of at least 0.02 seconds after T(ov)" should not be interpreted to mean "over at least 130% of normal voltage for a period of at least 0.02 seconds after T(ov)" and is not preferred as a solution. • Transgrid acknowledges AEMO's point that it is impractical to expect generating systems or IRS to remain in CUO for overvoltages without an upper bound, for durations up to 20 ms. However, we note that there should still be a requirement that provides coverage for switching and lightning surges. • We note that Option 5 + Option 6 provides comprehensive coverage against slow front over voltages, subject to the drafting providing clear technical requirements for assessing compliance. Further consideration should be given to Option 5 and Option 6. • Transgrid supports Option 4, to implement an appropriate ceiling voltage for the 20 ms requirement. • Transgrid also recommends adding appropriate drafting to outline the requirement to specify performance (beyond the Option 4 ceiling value) for slow front over voltages and lightning surges considering any instantaneous protection of the generating system (and relevant equipment) under the general requirements. This could be in the form of giving effect to Option 5 and/or Option 6 under general requirements.	
Clarification of continuous uninterrupted operation in the range 90% to 110% of normal voltage	**AGL – Support** • AGL considers current clause does not work for grid forming technology • AGL supports a ramp of 5 s, but requests more information on what "active power not substantially reduced" means (e.g. not more than 10% or no impact to power system security).	Respondents except Bo Yin, support the proposal for the assessment for a 10% voltage change. However, there were different views on the concept of assessing with a ramp, and some clarification requested around the use of "substantial" change. Bo Yin indicated, correctly, that this proposal does not avoid the 10-15% oversizing of inverter-based equipment to allow for retaining active power and

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	Amp Power – Support – with clarification • Amp Power generally supports AEMO's recommendation. • The term "not substantially reduced" for active power should be clarified (e.g., 5% or 10%). • It is also important to clarify the requirement is to prevent sustained change in output, not transient variations in active or reactive power. **APD – Support; additions proposed; issues raised** • APD supports AEMOs recommendation to make amendments to the definition for CUO in relation to NER S5.2.5.4(6). The steps proposed are a welcome amendment to better clarify the expectations from Generators and will hopefully reduce the variance in standards and assessment methodologies used through the NEM. • APD requests specification of whether the plant is required to meet these requirements under all control modes provided under S5.2.5.13 or only in specific control modes. • APD suggests that if assessment is provided in reactive power control mode it might not be needed in power factor control mode. • APD propose AEMO consider further amendments to clarify if fault response takeover controls should not be allowed to be triggered in the S5.2.5.1 operating region under some or all control modes. APD propose this [triggering of LVRT] could be allowed if the response has no change to active power and to provide more reactive power support to the network. • With the proposed updates to S5.2.5.1 capability curves there could be more assessment required, [for this rule] due to more corner points. • The 5 second ramp time might be too long. Consider 1 -2 seconds for AAS and longer duration ramp for MAS. **AusNet – Support with clarifications** • AusNet supports the proposed Option 2, with the following comments. • AusNet notes that the precise value of the (linear?) ramp time should be as short as practically possible (e.g., the 2 seconds as mentioned in AEMO's discussion section as opposed to the 5 seconds in the suggested drafting). The inclusion of the word 'substantially' within "…and active power not substantially reduced…" may introduce ambiguity and contention. AusNet recommends either to quantify what is meant by 'substantially' or omit the term. **Bo Yin – issue raised** • As the CUO requirement if interpreted according to AEMO 's clarificatory document in 2018 will normally require additional 10- 15% (of the installed plant capacity) reactive power equipment to be installed to fulfil. The suggested option 2 cannot reduce the need to install additional 10-15% (of the installed plant capacity) reactive power equipment. Because the voltage dependent PQ capability specified in S5.2.5.1 is static Q capability, it cannot be maintained during a voltage step which dynamic Q support is needed. **CEC – Support with clarifications**	reactive power capability for voltages down to 0.9 pu. However, AEMO's position, which seems to be supported by a majority of respondents is that there needs to be a balance between the cost of oversizing and the benefit of maintaining active power and voltage stability during common disturbances. AEMO considers that the proposed voltage range meets achieves that balance. AEMO's intent in this proposal is to focus on the sustained value of active and reactive power – when the voltage drops, retaining the capability for full reactive power injection, and when the voltage increases, retaining the capability for full reactive absorption. APD, AusNet, TasNetworks and Transgrid considered the 5 second ramp is too long. Transgrid and TasNetworks suggest that the assessment should be a step change, and TasNetworks suggests that the active power should be restored within 2 seconds, following a step. Transgrid noted that some network switching events cause voltage steps in the millisecond range, rather than seconds. Transgrid also commented that a voltage step is useful to test grading of inverter fault ride through thresholds to avoid FRT in the normal operating range to ensure that the plant does not enter FRT in the normal operating range. However, AEMO notes that there is nothing inherently wrong with entering FRT in the range 90-110% of connection point voltage, provided active power is not reduced, and there might be advantages, if it assisted to maintain voltages. In addition, AEMO notes that GFM inverters are expected to inject reactive current within the range 90-110%. AGL specifically supported a 5 s ramp. CPSA requested AEMO to confirm the intent was a linear ramp over 5 seconds. Other participants supported the option (5s) without specific reference to the ramp time. AGL, Amp Power, AusNet, CEC, CPSA and Goldwind all requested more clarity on the quantity of reduction, and Hydro Tasmania commented that unfavourable transformer tap position might make it difficult to achieve full reactive power output. Generally, there will be additional losses in a system when the reactive power injected or absorbed is increased to a high level, in response to a voltage change. This would be of the order of 1-2%. Reduction in active power at the connection point due to losses is usually considered normal. TasNetworks also suggested that a temporary reduction in active power for voltage reduction more than 10% (presumably also within the range 90-110%), could be allowed, where "temporary" was time taken for tapchanger response. AEMO notes that for solar farms, there can be an active power reduction for voltage increase, because high inverter voltage causes the DC voltage to

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Inconsistent interpretations of this clause across the NEM have caused uncertainty, risk and the need to install additional equipment (capex) to meet requirements and hence plans to address this are welcome. • Further clarity is required however on 'not substantially reduced' for active power, allowance for losses within the reticulation system, allowance for the reduction in reactive power due to voltage and • Confirm that the intent is for a linear ramping of voltage over five seconds. • Consideration of a voltage ramp is welcome and it is noted that the intent is to capture sustained reductions in power (typically due to current or MVA limiters) hence an overarching statement is required such that transient variations in active or reactive power are not interpreted to imply a failure to meet CUO. • **CPSA – Support with clarifications (same as CEC)** • Inconsistent interpretations of this clause across the NEM have caused uncertainty, risk and the need to install additional equipment (capex) to meet requirements and hence plans to address this are welcome. • Further clarity is required however on 'not substantially reduced' for active power, allowance for losses within the reticulation system, allowance for the reduction in reactive power due to voltage and • Confirm that the intent is for a linear ramping of voltage over five seconds. • Consideration of a voltage ramp is welcome and it is noted that the intent is to capture sustained reductions in power (typically due to current or MVA limiters) hence an overarching statement is required such that transient variations in active or reactive power are not interpreted to imply a failure to meet CUO. **Goldwind Australia – Support, with clarification** • Goldwind are in favour of the proposed changes to the CUO requirements. However, it would be beneficial if AEMO could provide a definition for what constitutes a "substantial" drop in active power (preferably as a percentage of Pmax), even if it is just a guide number that is included with the final rule change. **Hydro Tasmania – Support with clarification** • HT nominally supports option 2 but allowance should be made for existing transformer taps which may present difficulties in achieving the reactive output specified at all voltages where tap-changers are not installed, and the transformer tap ratio is not ideally matched to the connection point voltage. **TasNetworks – Partial Support; alternative option proposed** • TasNetworks' preference is that equipment should not disconnect for any voltage variations within the continuous operating band. However, a temporary power reduction for voltage reductions of more than 10% may be accepted, where 'temporary' is the time taken for tap-changer response. TasNetworks' preference is that the 10 % reduction is defined as a step	increase, moving the PV cells to a higher voltage, away from MPP. This can also be corrected by transformer action. In a connection through a DNA, the transformer action would likely be from the network side. AEMO proposes to adopt this suggestion. TasNetworks' suggestion of combining a step change with allowing 2 seconds for the plant to recover its active power adds a time dimension to the requirement. However, AEMO considers that transient response longer than 2 seconds is likely at least for reactive power, and possibly also for active power, considering that settling time is 5 s in the AAS of S5.2.5.13 currently and 7.5s in the MAS, for a 5% voltage step. AEMO has considered all the responses and has concluded that the specification on how to test the 10% variation would be better left to a guideline. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to revise the Draft Report recommendation, to: • Proceed with the 10% voltage change performance specification for active power change and reactive capability • Omit the specification of the methodology for assessment in the Rules. • Clarify that beyond a 10% step within this range and in other ranges in this performance standard, active and reactive power are permitted to change, but also that the active power reduction should be temporary, and corrected by tap-changer action. • Clarify that the performance to be measured is the change before and after the disturbance (ie post transient response). • Specify that active power within the 10% voltage variation should only change for losses, energy source availability, transient response, and for flexibility, any other reason that AEMO and the NSP consider reasonable in the circumstances. • Also propose to change references in the technical standards to nominal voltage instead of normal.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	change and the proponent is allowed 2s to restore their active power to pre-disturbance levels. **Tesla – Support with clarification** • Tesla is supportive of this change. As per comments on S5.2.5.1 above, we would also like to see these bands linked to nominal voltage rather than an NSP defined centre point. **Transgrid – Partially Supports; alternative option proposed** • Transgrid is in favour of Option 2, excluding the recommended ramp of 5 seconds. If applying a ramp is necessary for this assessment, we propose the ramp time to be in the order of milliseconds. • Reasons for this position include: – Rapid changes in voltages can occur in milliseconds from switching of reactive power and system events – Voltage step test is appropriate to test grading of inverter fault ride through thresholds to avoid FRT in the normal operating range to ensure that the plant does not enter FRT in the normal operating range – Using a ramp to assess could mask some actual plant limitations.	
NER S5.2.5.5 – Generating system response to disturbances following contingency events		
Definition of end of a disturbance for multiple fault ride through	**AGL – Alternative option proposed** • AGL supports option 3, which defines the end of a disturbance as when, following fault clearance, the voltage recovers to the range 90% to 110% of normal voltage at the connection point. **Amp Power – Support** • Amp Power generally supports the recommendation. **APD – Comments of a general nature** • APD raises some practical difficulties for MFRT compliance. **Ausnet – alternative option proposed** • AusNet supports Option 3 [which defines the end of a disturbance as when, following fault clearance, the voltage recovers to the range 90% to 110% of normal voltage at the connection point]. • This is based on the idea that once the voltage recovers to the nominal level, the voltage hysteresis points would have been cleared earlier in the recovery and the controller is likely to immediately switch back to its normal operating mode even if the broader event has not yet concluded. This also aids in consistency when calculating the active power recovery time. **Goldwind Australia – Support with clarification**	Respondents generally supported the concept of defining the end of a disturbance. However, there was some difference of opinion on the definition, particularly around whether to include remaining within the range 90 to 110% of normal voltage for a certain time as a condition. AGL and Ausnet preferred option 3 (excluding the time within the range). Amp Power, Goldwind, Hydro Tasmania, TasNetworks Tesla, Transgrid supported the proposed option 4 (including the time with the range). Transgrid however, preferred to include at least two faults with no recovery of voltage between them, on the grounds that it is possible to have two faults at the same time [in different locations]. In the worst case this would be in series, with no recovery. AEMO agrees with Transgrid that this condition is technically possible, although highly unlikely. However, inclusion of two faults simultaneously represents a whole additional class of double contingency event, which would extend the performance standards requirements further than contemplated by consecutive faults. The reclassification process is designed to accommodate this situation, where abnormal conditions make it a higher probability that simultaneous events or events occurring within the auto-reclosure time of circuits will occur. Considering the additional assessment burden and compliance risk the extended scope proposed by Transgrid implies, AEMO does not propose to make the amendment suggested by Transgrid.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• We support option 4. We would like AEMO to provide more clarification on whether the time required for voltage recovery to remain within the range of 90 to 110% of normal voltage may vary depending on the technology used? **Hydro Tasmania – Support** • HT supports option 4. **TasNetworks** • TasNetworks supports changing the definition to that proposed in option 4. **Tesla – Support** • Tesla is supportive of this change and believe it provides a helpful clarification. **Transgrid – Support; alternative option proposed** • Transgrid supports AEMO's intent in providing clarity on "end of a disturbance". However, we note that it is possible to have multiple fault events to occur at the same time or with 0 ms delay (for example, lightning strikes causing transmission line outages) and should be considered in the assessment of MFRT capability. • For the AAS, Transgrid suggest considering at least two faults, where the second fault commences immediately after the clearance of the previous fault (i.e., minimum clearance between the two faults is zero milliseconds) with the 15-disturbance sequence.	**Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation with the following clarifications: • Define the end of disturbance in relation to a voltage disturbance or fault condition, and not for a frequency disturbance • Apply the same end of a disturbance definition throughout the clause • The proposed definition includes recovery to within the range 90% -110% of nominal voltage and remaining in that range for at least 20 ms.
Form of multiple contingency ride through clause	**AGL – Partially supports; Alternative option proposed** • AGL supports the development of a suite of tests (option 5) • Consider performance assessment could be simplified to trip or not trip • Where there is zero time delay between faults, this means that the same fault continues for longer. It is unreasonable to expect plant to ride through "consecutive" faults when there is no time delay between them. **APD – Supports** • APD welcomes the suggested options 2 and 5. Even though best efforts to achieve AAS are to be made, this may not be possible to due to plant and network limitations. To handle such situations a suitable negotiation framework must be developed in the rules that will facilitate an efficient negotiation for a performances level between AAS and MAS. • MFRT capability varies between the generator technology. Some technology types, due their inherent capabilities with well-designed control systems will be able to meet the MFRT requirements with ease. However, technologies like Type 3 wind turbines, even with optimum controller designs, when subjected to series of faults in short time frames will lead to the plant's mechanical failure (eg; overloading of gear-train drive). Hence while formulating rule amendments the inherent limitations of such plants should be accommodated. • While defining consecutive faults the plant's under-voltage (UV) protection settings are to be considered. For example, consider two consecutive faults, the first with primary clearance	Respondents generally supported the concept of declaring limitations on multiple contingency ride through and having a test suite to assess the multiple contingencies, consistent with the rules for application of the tests in the current rules. There were a range of variations on what respondents thought was necessary or desirable in the test suite. AGL considered that CUO should be interpreted as not tripping for multiple contingencies. APD suggested that a suitable negotiation framework should be developed to facilitate an efficient negotiation of performance levels between AAS and MAS. AEMO considers that since there may be many different types of limitations, the negotiation needs to be flexible, and not detailed. AusNet suggested mandating cooling systems to improve reliability during multiple faults. AEMO does not consider mandating this is appropriate, but notes that if warranted, AusNet or AEMO may negotiate to remove a limitation. AusNet suggested that the NSP should provide the fault level and X/R ranges. AEMO concurs with this position, which is consistent with other proposals in the Draft Report. AEMO concurs with AusNet that protection settings should be considered for multiple fault ride through assessment.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	time and the second a CBF with a total clearance time exceeding 500 ms. Some generators set their UV setting as 0.5 s due to various limitations of the plant. Under such circumstance meeting the consecutive MFRT will not be possible. • The review has already considered the difficulty in defining MFRT fault sequence for assessments. The NER should provide more clarity on the fault sequences that will be acceptable to AEMO, NSP and the proponent. We understand this has been proposed and highly support this decision. **AusNet – Supports, with additions** • AusNet supports both Option 2 and Option 5 as suggested by AEMO. • Option 2: It is valuable to know the limitations not only that can be captured by power system models but also those are not able to be captured. However, AusNet notes that: – These limitations are deep embedded in inverter design, and which cannot be used by AEMO/NSP or developers to improve the MFRT performance. The key role for AEMO and the NSP is to define the minimum sets of requirements for OEM to achieve. The MFRT requirements set by AEMO should not be considered as an exhaustive list of all possible requirements for inverter MFRT design. Instead, these requirements represent a minimum set of performance criteria that OEMs should aim to achieve and exceed to ensure that their systems can maintain grid stability and reliability during times of multiple faults. – If relevant, AusNet recommends AEMO to mandate minimum standards on cooling system requirement, and it may direct OEM to increase cost to improve the reliability during times of multiple faults. • Option 5: AusNet notes and recommends that: – If the suite of tests established by AEMO becomes the primary focus of inverter design, there is a risk that OEMs will prioritize meeting the test requirements over addressing the challenges of real-world operating conditions. Therefore, the diversity and typicality of the design tests, as well as adaptivity and robustness, need to be considered. – The NSP must be consulted when providing the suggested fault level, X/R ratio ranges as well as the critical fault clearance time for nominated set of contingencies to aid in plant MFRT design/configurations. – It is practical to impose a requirement on the proponent to declare in proposed performance standards any impediment to MFRT and provide evidence to support the declaration. Additionally, it might have additional benefits if AEMO can design a generic check list/questionnaire based on experience accumulated via past project experience on modelled and non-modelled MFRT limitations which may set up a baseline for OEMs. Moreover, mandating the MFRT protection details to be provided is of importance. – AusNet supports establishing ongoing compliance obligations for proponent to maintain the MFRT performance standard throughout the life of the plant. **CEC – clarification**	CEC sought clarification on how the test suite will be developed. Hydro Tasmania was concerned about testing implications for this proposal. As currently is the case for MFRT, the assessment will largely be by means of simulation. However, in the event that the plant is subjected to multiple faults in reality, the plant will be expected to ride through conditions within the envelope of operation defined by the performance standard (ie the rules around fault duration, depth and etc. currently in the clause, with the clarifications on end of a disturbance, and allowance for up to two faults overlapping in time), unless there is a specific limitation declared. The model is ultimately tested by comparison with performance in real events. However, the DMAT does also ask for Hardware in Loop (HIL) tests. These would help to provide confidence to participants in drafting proposed performance standards. AEMO agrees with Transgrid's comments that HIL tests might provide a form of evidence about specific limitations of the plant that need to be listed in the performance standards. AEMO doesn't see any need to document this in the rule. AusNet, TasNetworks and Transgrid suggested that, as NSPs, they should have the ability to add to or develop the Test Suite for specific conditions. TasNetworks suggested that Tasmania could have a single set of tests that was relevant to all connections. Other respondents supported AEMO developing a single test suite. Tesla suggested that the tests would be more scalable if not made site specific, and that OEMs might be able to undertake lab-tests against the AEMO test suite, which can be used to support multiple projects. However, AEMO is not convinced that site-specific settings are not relevant to MFRT capability, as suggested by Tesla. Following further consideration of the feedback and the value or otherwise of a test suite that is not site specific AEMO has instead decided to place an obligation on NSPs to provide advice to Connection Applicants if requested, on combinations of contingency events that are likely to be onerous for compliance considering site-specific conditions. As implied by TasNetworks and Transgrid's responses, the NSP is in the best position to know the conditions that tend to put their network under most stress, which will also be those that are likely to cause the most difficult conditions for connecting plant. It will be in the interest of all parties to uncover specific limitations by focussing on these severe conditions, rather than mandating studies or as is the case now, randomly combining contingencies. Balancing NSP views with the intent to limit the effort required for this clause, AEMO proposes to allow NSPs to request other studies where they have reasonable grounds to believe there might be an inadequately disclosed limitation. This could include something that is not disclosed or a limitation that is inadequately defined, and which needs to be made more specific.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Has AEMO considered putting these requirements in separate guidelines? • It isn't clear how the common suite of tests will be developed and how the alignment between the model and tests results be assessed (aside from HIL). **Hydro Tasmania – Strongly supports, with clarification** • HT strongly supports this rule change and supports AEMO's recommendation as proposed but notes the common suite of tests should consider the following item as noted in relation to machine stability as outlined in the following subsections for this Clause. • Furthermore, without any additional details on the proposed "suite of tests" at this stage consideration should be given to balancing the need for demonstrating compliance via testing vs stress put on generating units as part of testing. • HT would also like to seek confirmation/clarification that the requirement "throughout the life of the plant" is limited to actual events rather than being expected to routinely test / apply faults to demonstrate compliance. **TasNetworks – Supports option 2; Alternative proposed option (3 instead of 5)** • TasNetworks' preference is for a combination of options 2 [disclosure of limitations] and 3 [NSP to define test cases to assess]. • Due to the nature of the Tasmanian network, TasNetworks would use a consistent set of study cases for each connection removing the concern about the level of resources required. **Tesla – Supports, with clarification** • Tesla is supportive of the proposed approach of AEMO developing a suite of tests that incorporate the MFRT requirements. However, this solution will be far more scalable where the tests are consistent and there is no need to consider site specific settings for a particular plant. In the absence of site-specific settings, OEMs would be able to undertake lab-tests against the AEMO test suite which can be used to support multiple projects. • Site-specific settings will not be relevant to MFRT capability. **Transgrid – Supports Option 2; Supports Option 5 with clarifications; Alternative proposed** • Transgrid supports Option 2 (disclosure of MFRT limitations) and Option 5 (AEMO test suite), with priority for amendments to give effect to Option 2. For Option 5, allowance should be made for NSPs to request additional MFRT scenarios if deemed necessary, based on proposed connection location. • Transgrid notes the requirement in the DMAT to provide confirmation that the plant model is fit for multi-disturbance application and evidence provided in the form of type tests or hardware-in-loop. Therefore, Transgrid suggest further consideration be given to Option 4 (HIL) as a form of compliance evidence, given the limitations of simulation models. Note that this can form part of the Option 2 evidence.	**Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation to progress the requirement for disclosure of specific limitations, and to make the MAS CUO requirements subject to those specific limitations, but make the following changes regarding the assessment arrangements: • not progress the proposed test suite concept, but instead place an obligation on the NSP that, if requested by the connection applicant, the NSP must advise the combinations of contingency events likely to be onerous, considering site specific factors; and • provide the NSP the flexibility to require additional studies only where it has reasonable grounds to believe there is an inadequately disclosed limitation.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
Number of faults with 200 ms between them	**AGL – Support** • AGL supports the proposed option. **APD – Support** • APD agrees with the recommended option. However, when a technological limitation such a mechanical load limits are evidenced, the rules should provide sufficient flexibility to negotiate the time gap between the faults for assessments. **Ausnet – Support** • AusNet supports the proposed Option 2 as a technology and risk profile-based approach. **Hydro Tasmania – comment** • For synchronous generators the application of multiple close-in faults may see individually recoverable faults accumulate to irrecoverable instability due to machine inertia and governor systems and turbine control response limitations. • As such the number of faults and suite of tests should be carefully determined to ensure a credible performance benchmark is established that is consistent with the intent of ensuring power system security whilst minimising academic compliance activities. • HT also notes complexities may arise with identifying a credible fault scenario in relation to the standard suite of tests, and allowance should be made where multiple fault ride through is not credible (e.g., the location of the 'multiple faults' is not credible based on TNSP protection having operated to disconnect a generating unit requiring operating initiated machine reconnection). **TasNetworks – Support** • TasNetworks supports having the MAS for MFRT defined using the six faults and 200 ms combination criteria, and allowing specific limitations to be carved out of these requirements. **Tesla – Support** • Tesla is supportive of this change and the proposed carveouts. **Transgrid – Support** • Transgrid supports Option 2: leave requirement for up to six faults and 200 ms and combination criteria as is but allow specific limitations to be carved out of these requirements.	There is strong support from respondents to amend the MAS as proposed, to retain the requirement for 6 faults within 5 minutes with carve outs for specific limitations. AEMO notes Hydro Tasmania's comments on multiple fault impacts on synchronous machines. This is an example of a type of issue that the amendment is intended to address. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation, with minor clarification that the specific limitations should not reduce the number of disturbances below that described in the MAS (i.e. up to 6 disturbances).
Reduction of fault level below minimum level for which the plant has been tuned	**AGL – Support with clarifications** • AGL is not opposed to recording the range of fault levels in association with the performance standards (as proposed in option 4) • AGL considers the document should also reference relevant plant characteristics – for example, due to PLL technology the plant may experience oscillations. On this basis we suggest not using the term "operate stably" as it does not account for these characteristics.	In the Draft Report AEMO suggests that plant should not be required to remain in CUO at levels lower than the lower bound of the fault levels for which they have been tuned. Practically they may remain connected, but with some deterioration of response when the fault level is lower than they have been tuned for, but at some point they will likely be unstable. This level may be above the SCR level described in S5.2.5.15. The proposed documentation of the tuning range is so that a review of performance can be initiated based on actual fault levels reducing to be close

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• AGL considers that any amendments should deal with a situation where a plant cannot be retuned to match the reduced fault level. **Amp Power – Issues raised** • Amp Power expressed concern that an NSP could require returning of plant, since it would require significant time and cost to generators/IRPs over the life of the plant. Will there be a cost recovery mechanism for this? **APD – Issues raised** • The connecting NSP defines minimum and maximum fault levels (FL) at PoC. The minimum FL determined by the NSP is not corresponding to N system but to N-1 or sometimes N-2 conditions. The plant is assessed and remediated for this minimum FL prescribed by NSPs. In order to accommodate any fault level reduction during MFRT events and to make the plant operate satisfactorily under those network conditions will further burden the plants. • It is not always possible to make the plant ride-through reduced MFRT FL conditions just by setting changes. It may require additional remediation to compensate the performance which will increase the cost of connection. • Tuning a controller for the worst MFRT conditions may not guarantee satisfactory performance for normal FL ranges. **Ausnet – Partial support;** • The solutions described in this section appear to be addressing two different aspects; one on valid SCR limits within an MFRT assessment, another on a need to allow for the alteration of plant settings should the SCR shift below limits during the plant's life. AusNet feels these two matters should be separated rather than attempting to address them as a single issue. • Regarding the SCR falling below an acceptable limit during MFRT studies, AusNet agrees with the concept of a minimum valid SCR disclosure, be it within the GPS or within the RUG (i.e., option 3 or 4). • Regarding potentially requiring plant settings to be altered due to a lower SCR manifesting later in the plant's life (i.e., Option 6), this should be evaluated as a separate matter outside of this MFRT context. Furthermore, AusNet has concern that the setting changes that may be necessary to maintain stability under low SCR conditions may affect the agreed performance standards, which would trigger a 5.3.9 process anyway. For example, if lower k-factors are required to maintain stability following a fault, this may result in fault recovery times or reactive injection amounts not consistent with the current GPS. • In any case, SCR values which change over time and the plants need to cater for such changes should not form part of this MFRT issue. **CEC – Partial support; issues raised** • The enablement of an NSP to require retuning of plant would require significant time and cost to generators over the life of the plant. Will there be a cost recovery mechanism for this? Noting there is work under the CRI looking at the 5.3.9 and S5.2.2 process and the	to the tuning range, such that a single fault, combined with a prior outage might cause the fault level to be outside the tuning range. It is better to identify the need to change tuning instead of waiting for an incident where the plant goes unstable. Some respondents expressed concern about having to change settings because their plant does not meet its GPS requirements. This is not a new requirement, but exists under S5.2.2, whereby: *"If the Network Service Provider or, if the requirement is one that would involve AEMO under clause 5.3.4A(c) of the Rules, AEMO, reasonably determines that a setting of a generating unit's control system or protection system needs to change to comply with the relevant performance standard or to maintain or restore an inter-regional or intra-regional power transfer capability, the Network Service Provider or AEMO (as applicable) must consult with the relevant Generator, and the Network Service Provider may request in writing that a setting be applied in accordance with the determination."* Documenting the range of fault levels serves two purposes: • If, as proposed, CUO is not required for fault levels below the minimum tuned level, it provides a reference for that information; and • It can also be used to identify, without waiting for a failure, where it is likely that retuning of the plant is needed for compliance with performance standards. Note that at present the plant is required to comply with its performance standards regardless of the fault level changes in the future. Under this proposal, compliance for individual faults is still expected, but for MFRT, the plant would not be required to remain in CUO. In response to CEC and CPSA, AGL, Amp Power, and Hydro Tasmania, the issue of retuning and compensation or otherwise for it is outside the scope of this review. There is another review considering changes that might be required to S5.2.2. AGL some participants raised concerns about what would happen if the plant was unable to be retuned for a lower fault level. The clause S5.2.5.15 deals with the short circuit ratio for the plant, which would translate to a minimum fault level, for which the plant can be tuned. Tuning would be at this level or higher. Note that the obligation to document the range of fault levels for which the plant has been tuned does not remove the Participant's obligation to comply with its performance standards. Documenting the range of fault levels will provide more clarity on if the plant is at risk of non-compliance, because of a mismatch between the tuned range and the actual fault levels on the power system.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	concept of retuning more generally, so it will be critical to coordinate any developments here with that workstream. • How this is actually assessed also requires due consideration - at what point is the plant expected to enter unstable operation? • If Options 4 and 6 are progressed, noting that a fault level range is not captured within the NER, and considering that changes to fault level settings (gains) would be required, is AEMO's position that a 5.3.9 alteration would not be required, only an S5.2.2 setting change request? • A potential solution is for minimum fault level that the plant has been tuned should be documented in the GPS and RUG, and S5.2.2 setting change request will apply if the future fault level dropped below the minimum. However, this should not be deemed as generators' obligation solely as the future fault level decreasing is systematic matter, and the responsibility and obligations should be stated clearly. **CPSA – Comment** • The enablement of an NSP to require retuning of plant would require significant time and cost to generators over the life of the plant. Will there be a cost recovery mechanism for this? Noting there is work under the CRI looking at the 5.3.9 and S5.2.2 process and the concept of retuning more generally, so it will be critical to coordinate any developments here with that workstream. **Goldwind Australia - Support** • Goldwind support the implementation of Options 4 and 6. **Hydro Tasmania - Support** • In principle, HT supports AEMO's recommendation of options 4 and 6. • However, HT would like to seek clarification, what extent would a fault level need to change for NSP to request retuning. Without any additional details or criteria, it may expose participants to excessive/frequent requests from the NSP to retune plant and/or apply setting changes even though triggering factors are outside respective participant's control. Consequently, providing a heightened level of uncertainty for participants. Furthermore, at this stage it seems unclear who would carry the financial impact of implementing changes when requested by the NSP. • HT would also like to highlight the fact that for synchronous machines the sub-transient reactance of the generator and positive sequence reactance of the transformer are inherent to their design and as such do not provide much scope for fault level tuning. • More generally, HT notes that while coal fired synchronous machines will gradually be phased out, the green and synchronised hydro machines will remain. • This fact should be well considered and incorporated in the discussion for this Clause S5.2.5.5. **TasNetworks – Additional requirements**	Ausnet suggests that the proposal deals with two different aspects – one on valid SCR limits within MFRT assessment and the other on the need to allow for alteration of plant settings should SCR shift below limits during a plant's life. AEMO notes that the latter is already allowed for in S5.2.2 and the change proposed is only to document the range of fault levels for which the plant is tuned. Hydro Tasmania asks how much a fault level would need to change to trigger a request for retuning. There is no specific trigger for retuning, but it is the Generator's responsibility to manage its compliance with its GPS. The information that the fault levels on the power system have reduced to an extent that credible contingency events might cause the plant to be operating outside of the tuning range should trigger the Generator to examine its compliance with its GPS, and might lead to a request to change its settings. The current situation is not different except that there is no transparency about the range of fault levels for tuning. at present. In response to APD's comment regarding additional work to account for fault level reductions during MFRT, AEMO notes that failure to account for fault level reductions in MFRT would lead to overly optimistic compliance assessment. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Generators should be required to nominate a minimum guaranteed floor for stable operation (down to a short circuit ratio of 3) and a level where they would be permitted to disconnect. This would provide a 'floor' to design to. • Tripping should be seen as the last resort. Instead, generators should try to stay connected even if that means they are temporarily non-compliant with some aspects of their generator performance standards (GPS) during contingency events. **Tesla – Support, with caveats on process** • In respect of NSP plant retuning, Tesla is only supportive of this approach if there is a clear MFRT carve-out in the 5.3.9 amendment process. We would not support any retuning if it involved a full 5.3.9 review. There is precedence for this approach with the introduction of PFR resulting in a limited 5.3.9 amendment process with clear guardrails. Any NSP retuning linked to MFRT should be treated in a similar manner to reduce inefficient spend and the considerable time taken in working through a full scope 5.3.9 review process. **Transgrid – Support** • Transgrid agrees that assessment of MFRT capability in a SMIB environment without considering the reduction of the system fault level due to multiple outages could lead to overtly optimistic results for MFRT assessments. • Transgrid acknowledges that it would be good to assess the lowest fault level the plant can operate stably and remain connected, with the plant settings tuned to achieve compliance for the minimum and maximum fault level range stipulated by the NSP. • Transgrid supports Option 6 to having flexibility to request an amendment process if there is a risk that the plant will be non-compliant due to further reduction of fault levels.	
Active power recovery after a fault	**AGL – Supports** • AGL supports the proposed option. **APD – Supports** • APD accepts AEMO's recommended changes to align the active power recovery time with the voltage recovery. However, in many occasions it has been noted that the active power recovery is also interpreted as an requirement for MFRT faults. Since some technologies, like type 3 wind turbines, struggle to meet recovery time standards for subsequent faults due to mechanical loading limits and hence it would be good to clarify in the amended rule that the active power recovery time is applied for isolated faults only. **Ausnet – Supports** AusNet agrees with Option 2, but for the equivalent wording relating to connection point voltage and frequency disturbance only. That is, it is not appropriate to include "a period agreed by the connection applicant, AEMO and NSP" for the AAS, similar to MAS under ERC0272. **Bo Yin – Issue raised**	Respondents generally support the proposed changes. Transgrid suggests that AEMO should define "return to 95%..." in this clause as being the "first instance at which active power reaches 95%...", because the active power could go below this value again. AEMO instead proposes to link the clause to the definition of "end of a disturbance" used for MFRT, which requires remaining in the range 90-110% of nominal voltage for at least 20 ms. For this issue AEMO considered how the inertial response, phase jump response and primary frequency response might be incorporated. The effect of primary frequency response can be incorporated in a similar way to what the AEMC has done in the MAS for active power recovery in its most recent change to S5.2.5.5. The phase jump response and inertial response can have significant impact on the active power response and will be very dependent on the disturbance. While it might be desirable to capture this behaviour in the AAS active power recovery clause, to accommodate grid forming technology in the AAS, AEMO has not found a practical way to do so, and but a negotiated access standard could allow for the consideration of these behaviours. **Revised recommendation**

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Consider a different requirement for an extended fault scenario where the voltage retains around 70-80% for a rather long time. In this scenario active power should not wait until voltage recovers to 90% of nominal. **Goldwind Australia – Support** • Goldwind supports Option 2. **Hydro Tasmania – Support** • HT principally supports AEMO's position but shares concerns on how AEMO deals with frequency, inertial and active power response. HT believes this should not be finalised until the draft determination is published such that the exact wording to this clause can be confirmed. **TasNetworks – Support** • TasNetworks supports the proposal to incorporate the changes made for the MAS into the equivalent wording for the AAS. **Tesla – Support** • Tesla is supportive of this change. **Transgrid – Supports with clarifications** • Transgrid supports Option 2 to change the AAS to be consistent with AEMC's draft determination for the MAS (equivalent to this clause). • However, Transgrid suggested to include definition of "recovery" to be the "first instance at which the active power reaches 95% of the pre-fault level" for instead of the ambiguous term "return". This is especially important to remove ambiguity of the performance requirements if the active power has overshoot/undershoot/oscillations while the voltage is stabilising in the 90% - 110% range.	Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation with the following revisions to: • amend the MAS to include reference to clause 4.4.2(c1) for primary frequency response where S5.2.5.11 has been referenced in regard to a frequency disturbance, and include frequency response in the AAS. • apply consistent conditions for synchronous machines. AEMO also recommends using the same definition for "end of the disturbance" as proposed for MFRT.
Rise time and settling time for reactive current injection	**AGL – Support** • AGL supports the proposed amendment but would prefer inclusion of parameters around what "adequately controlled" means. **Amp Power – Support (with clarifications)** • Amp Power generally support AEMO's recommendation however the term "adequately controlled" requires further clarification. Prefer a definition in the NER. **APD – Supports (with clarifications)** • In the draft rule, the term 'adequately damped' has been replaced with 'adequately controlled'. APD understands the rationale for this update as described in the draft determination. However, APD sees this as an item for differences in opinion among AEMO, NSPs, OEMs and proponents in comparison to the previous term with a more prescriptive definition in the Glossary (Chapter 10 of the Rules). This new term will be part of the normal next, i.e. not italicized. This may lead into some form of ambiguity among stakeholders similar to the term 'maximum continuous current'. Therefore, APD strongly recommends the	Most respondents supported the changes to make the AAS consistent with the proposed changes to the MAS for the performance of reactive current injection controls. Largely respondents agree with removal of settling time, with the exception of TasNetworks and Transgrid. TasNetworks proposed keeping the risetime and settling time for simulation but excluding them for ongoing compliance (because it can be influenced by external conditions). AEMO notes that, especially under low fault level conditions, the response of the plant itself can modify the voltage that it is measuring, and can also influence the risetime and settling time. Transgrid preferred retaining settling time, stating that it provides a clear criterion for performance and incentive for the justification to be provided for negotiation purposes. However, AEMO considers that settling time is not an appropriate measure where the response includes more elements than would be apparent in a simple second order control system. There are, however, multiple respondents who sought clarity on the term 'adequately damped' which has been adopted in the MAS by the AEMC, as an

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	new rules should include a clear and concise definition of the term 'adequately controlled' in the Glossary. **Ausnet – Supports (with clarifications)** • Whilst generally supportive of Options 2, 4, 5 and 6, AusNet notes that the wording will need to be carefully considered. As it stands, there are elements of the current wording in the AEMO proposal which may be interpreted to make the AAS more permissive than the MAS proposed under ERC0272. For example, whether the commencement time should be measured at the connection point (as the ERC2072 MAS offers a choice of connection point or inverter terminal) and whether the ERC0272 MAS should also include the "step-like" qualification to the rise-time criteria. **CEC – issue raised** • Removal of adequately damped is welcome, however some clarity is required on what is 'adequately controlled', else it is likely to be interpreted inconsistently. **CPSA – Issue raised (same as CEC)** • Removal of adequately damped is welcome, however some clarity is required on what is 'adequately controlled', else it is likely to be interpreted inconsistently. **Energy Queensland - Support** • Both Ergon Energy and Energex acknowledge the challenge in measuring the settling time in an actual fault. **EUAA - Support** • The EUAA supports AEMO's recommended approaches to reactive power to improve system stability. **Hydro Tasmania – Support, with clarification** • HT supports options 2, 4, 5 and 6, however HT is of the opinion that the 10ms commencement time is too quick. A minimum of 20ms should be allowed, with allowance under the MAS for slower commencement times for e.g., DC rotating or brushless excitation systems (i.e., to allow investment to digital regulation technology whilst preserving power stage until further investment can be afforded). **TasNetworks – Alternative option proposed** • From a "control theory" perspective, there is nothing exceptional in the power system's response to reactive current injection even under low system strength conditions and therefore the standard terms commonly used in control theory can remain. The dynamic model acceptance tests (DMAT) use a passive single machine infinite bus (SMIB) arrangement when assessing such performance and so clearly the observed dynamics are then only due to the equipment under test. Under the controlled DMAT environment (and the similar "SMIB" tests used during "R1" assessment) the formal control theory wording should remain.	alternative to "adequately damped" for the MAS and proposed by AEMO for the AAS. In response to Hydro Tasmania, AEMO notes that its Draft Report recommendation relates to the AAS, rather than the MAS, which the AEMC has recently amended. The issue raised should be considered under a negotiated access standard. The final rule, which has commenced, includes: … (3) the reactive current rise time must be no longer than 80 milliseconds or a longer time agreed to by the Network Service Provider and AEMO; (4) the reactive current response must be adequately controlled (5) the reactive current response must commence within a period after the response initiating condition of (i) 40 milliseconds; or (ii) a longer time agreed to by the Network Service Provider and AEMO. Ausnet raised points on whether the Draft Report recommendation (which was published before the final determination of the rule) might be more permissive than the MAS. AEMO considers it reasonable to reflect a shorter risetime in the AAS, omit the settling time and use adequately controlled in the AAS also. Respondents were generally supportive of options 4, 5 and 6. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation with the following revisions to: • Make a definition for adequately controlled. • Qualify that risetime is to be assessed for steplike voltages (this will affect MAS and AAS)

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• However, with actual on-site "R2" testing and full model verification, other voltage regulation devices can impact the voltage profile and there is justification at the R2 stage for relaxing the wording. **Tesla – Support, with clarifications** • Tesla is very supportive of the recommendation to omit settling time from the AAS. In respect of the recommendations made for rise-time requirements we would recommend one of the following options: – Align with the final changes made to the MAS in ERC0272 which has a commencement time standard that requires a reactive current response to start within 40ms of a fault (rather than 10ms); or – Include additional clarifying language that specifies that that the commencement time is less than 10ms from the time the voltage drop is measured at the connection point. **Transgrid – Partial Support; Alternative proposed for Option 2 (settling time removal); clarification** • Transgrid prefers Option 3 rather than Option 2, modified as appropriate for AAS. Omission of settling time for AAS, especially if the MAS settling time is removed, will remove a quantifiable criterion against which the plant can be tuned and assessed against. Option 2 will also remove incentive for generator applicants to provide justification for proposed performance capability and prolong the negotiations on the proposed performance as it will be subject to individual interpretation of adequate control. Retaining the AAS (which may be modified as suitable) provides a clear criterion for performance and incentive for the justification to be provided for negotiation purposes. • Transgrid supports Option 4, provided that "adequately controlled" is clearly defined in the NER. • Transgrid supports Option 5 and Option 6, noting that reactive current commencement time in Option 6 needs more clarity, or the option to define it in the GPS.	
Commencement of reactive current injection	**AGL – Support** • AGL supports the proposed option. **APD – Support** • APD agrees with the recommendations for large reticulation systems. A wider margin might be required between the Vpoc and Vterm for the commencement of the Iq response to accommodate the variations in Vpoc for different operating points, i.e. in voltage droop control. • For example, for a plant with voltage droop control Vref=1.05pu and 12.7% droop on Pmax (5.16% on Qbase), Vpoc varies in the range of ~1.0-1.1pu. Assume the grid transformers' OLTC regulates the Vterm close to the 1.0pu all the time. In order to ensure the Iq response is started when Vpoc drops to 0.85pu under all operating scenarios, i.e. Qmax and Qmin, the generators need to start the Iq response when Vpoc drops by a step size in a range of	Respondents generally supported the proposed change to require voltage response for an undervoltage event to commence above 85%, and below 115% for an overvoltage event. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.

<table>
<tr><th>Issue</th><th>Schedule 5.2 Generator recommendation feedback summary</th><th>Consideration of issues and revised recommendations</th></tr>
<tr><td></td><td>0.25pu (1.1->0.85pu) to 0.15pu (1.0->0.85pu). This means the LVRT threshold should be higher than 0.85pu.
• On the other hand, there is a requirement from some TNSPs on the CUO in response to the voltage disturbances (S5.2.5.4) as to the generating system must remain in CUO when Vpoc drops to 0.9pu under all operating scenarios. This means when the plant operates in Qmax (Vpoc= 1.0pu) a 0.1pu drop occurs and in Qmin (Vpoc= 1.1pu) a 0.2pu drop happen for 0.9pu disturbance. A corresponding voltage step at the terminals will result in 0.9pu and 0.8pu level which the later triggers LVRT.
• To streamline connections, a standardised assessment methodology in connection with reactive current injection commencement should be included to ensure that the industry applies a consistent approach for the assessing reactive current response. Other definitions could be used, but there would need to be a clear and unambiguous definition of all terms to avoid existing issues in the due diligence phase where there can be different interpretations on these performance aspects.
Ausnet – Support
• Ausnet supports the proposed option 2.
TasNetworks – Support
• TasNetworks supports this proposed change.
Transgrid – Support
• Transgrid supports Option 2 for AAS to specify that reactive current response needs to commence above 85% of normal voltage for an undervoltage event, and below 115% of normal voltage for an overvoltage event.</td><td></td></tr>
<tr><td>Clarity on reactive current injection volume and location and consideration of unbalanced voltages</td><td>AGL – Support (with clarifications)
• AGL notes that for option 2 “system stability” and “range of system impedances to which the plant may be exposed” requires clarity
• AGL supports option 3
• Regarding capturing negative sequence contribution (option 5) – AGL notes that capturing negative sequence by way of a percentage only works if it operates in the same way as a positive sequence contribution.
Amp Power – Issues raised
• Amp Power suggest to not record any settings in the GPS as this will significantly increase the risk of modifying GPS in the future which can be a time consuming and expensive process. Only performance is to be recorded.
Ausnet – Supports (with extra considerations)
• AusNet invites AEMO to consider whether a broader change to the standard should be made to allow control schemes implemented in ABC stationary frame with ideal balanced reference voltage for individual phase control assessment. Adopting per-phase compliance standards would mean healthy phase voltages would not be under/overcompensated to</td><td>AEMO’s proposed approach in the Draft Report included four options: 2, 3, 4 and 5.
Option 2 – retaining the 4%/% and 6%/% capability requirement but clarifying that the settings achieve best outcomes for plant and power system stability for the range of system impedances to which the plant may be exposed.
Respondents either largely supported or did not comment on this proposal. AGL suggested more clarity is required on “system stability” and “range of system impedances to which the plant may be exposed”. Ausnet suggested that AEMO clarify that the range of system impedances includes varying X/R ratios. Transgrid suggested omitting the clarifying statement as Transgrid considers it ambiguous.
Ausnet also suggested that the requirement is bounded by applicable current limits, and relevant priority modes (Iq or Id). AEMO notes that the existing rule already allows the reactive current injection to be limited (NER S5.2.5.5(u) to maximum continuous current), which the rules (following the recent Rule change) define as
In respect of a generating system:</td></tr>
</table>

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	have unexpected voltage issues. This mechanism will inherently remove the unbalance, and where the appropriate plant can perform this function, would be a more reasonable standard for IBR equipment with which to comply. • However, regarding AEMO's proposal as it stands, AusNet generally supports changes with the following comments: – Option 2: Regarding the term 'system impedances', acknowledge that the term encompasses varying X/R ratios. Add a recognition that the requirement is bounded by applicable current limits and any relevant priority modes (e.g., IQ vs. ID). – Option 3: Revise the general requirements to include the selection of positive and negative sequence currents to mitigate the impact on healthy phase voltages. It would also be advantageous to set a limit for the maximum deviation on individual phase voltage (% change from the predisturbance phase voltage) and specify that the voltage of healthy phases must not exceed 110% under any circumstances. In addition, AusNet suggests including the negative sequence currents definition in the NER, currently there are only definitions of negative sequence voltage and negative sequence to positive sequence components of reactive current contribution are included. – Option 4: Suggest defining for positive sequence current and voltage. – Option 5: The negative sequence control should not be overly prescriptive due to the X/R ratio being dictated by angle of the fault impedance. **EUAA - Support** • The EUAA supports AEMO's recommended approaches to reactive power to improve system stability. **Goldwind Australia – Support with clarifications** • Goldwind support option 3 and recommend that it be implemented at the connection point, but only be applicable during fault conditions and not during normal operation of the plant. • Regarding option 5 to capture the negative sequence contribution, the current requirement is to agree on the ratio of negative sequence to positive sequence with both AEMO and NSP. Should this requirement be changed? • We recommend that it should be changed because the ratio of negative to positive sequence is not fixed and varies depending on the fault's nature. **Hydro Tasmania – Partial Support; issues raised** • HT has no issue with option 2. • HT is of the opinion that options 3 and 5 should not apply to synchronous generators or 3-phase induction generators. For these types of machines this should be an outcome of the performance standard requirement of the machine as it is not possible to control voltage level for different phases.	(a) where assessed at the *connection point*, the current at the *connection point* corresponding to the largest amount of *apparent* power required by the *generating system's performance standard* under S5.2.5.1, at the *normal voltage*; and (b) where assessed at any other point, the current at that point assessed in the manner agreed by the *Network Service Provider* for the *transmission system* or *distribution system* to which the *generating system* is *connected* and recorded in the *connection agreement.* ***Option 3*** – proposes to establish an AAS requirement to minimise the voltage deviation on each phase from normal operating voltage, subject to a stability criterion. There are a range of views on this proposal: AGL supported the proposal. Transgrid supported it as a principle, but questions if it should be in the AAS. Goldwind supported it but suggested it should only be applied during a fault. Ausnet suggested there should be a general requirement, to minimise impact on unfaulted phases. AEMO notes that the AEMC has already introduced something similar in the recent rule change (NER S5.2.5.5(u)(1A): the reactive current contribution must not contribute excessively to *voltage* rise on unfaulted phases during unbalanced faults; Hydro Tasmania suggested the requirement should not apply to synchronous generators or 3-phase induction generators, as they can't control their contribution. ***Option*** 4 – proposes defining the reactive current injection for positive sequence currents and voltages. This option was generally well supported. Hydro Tasmania expressed concerns about compliance testing. However, AEMO notes that it is not generally possible to test fault response in the field and this is usually done by simulation and by analysing plant response to network events over the life of the plant. ***Option*** 5 – proposes to capture the negative phase sequence contribution. AEMO sought input on how this should be described. AGL notes that capturing negative sequence by way of a percentage only works if it operates in the same way as a positive sequence contribution. Ausnet commented that the negative phase sequence should not be overly prescriptive due to the X/R being dictated by the angle of the fault impedance.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Further, this clause should also consider how the voltage regulator measures voltage as systems may measure from e.g., ‘Vee’ connected Vr-w and Vb-w phase only, and from this regulate to average voltage, possibly after deriving the third voltage. • I.e., Synchronous machine cannot vary per-phase voltage and may not be able to respond to anything other than average voltage or positive sequence voltage based on 2 or 3 phase voltage measurement, in ph-ph or ph-e arrangement. • This could be due to regulator measuring requirements, or voltage transformer connections onsite (e.g., no 4 wire-Y connected VT). • HT believes the risk to disincentivising investment in upgrading plant should be considered carefully for these clauses. With respect to option 4 HT has concerns regarding compliance testing and additional tests requirements introducing further ambiguity for little real gain. Consideration should be given whether this could be an outcome of the model / model verification only. **TasNetworks – Support, with clarification/comment** • In terms of reactive current, the word “injection” refers to supply, export, boost etc. i.e. a capacitive response and the National Electricity Rules (NER) is correctly drafted when referring to positive sequence voltage. However, care must be taken with the definition of reactive current in response to negative sequence voltages. There should be a requirement to minimise voltage deviation (i.e. reduce negative sequence voltage), which should therefore cause the current components that are in negative phase sequence to be absorbing reactive current in response to negative sequence voltages. **Tesla – Support with clarifications** • Tesla is mostly supportive of this proposed change, however we make the following recommendations in respect of Option 5 and the question asked by AEMO on negative sequence – we would recommend that instead of defining the ratio of negative sequence, current should be defined as a function of negative sequence voltage. Alternatively, the negative sequence current injection should be outcome-focused. For example, supply sufficient negative sequence current during an unbalanced fault to ensure that the healthy phase voltage does not rise above 1.10 pu. **Transgrid – Support with clarifications** • Transgrid supports Option 2 for AAS, excluding the suggest clarifying statement. Transgrid supports Option 2 to retain the AAS criteria but finds the suggested clarifying statement to be ambiguous. The requirement to achieve best outcome considering plant and power system stability should be covered in the negotiated access standard (and to an extent is already covered broadly under clause 5.3.4A negotiation framework). • Transgrid is in support of the considerations outlined in Option 3, however appropriateness in including this under AAS should be considered. • Transgrid supports Options 4 and 5. Transgrid would like the NER to provide clear criterion on the reactive current strategy requirements for unbalanced faults. In our experience, majority of the connection applicants currently do not have clarity on this requirement	Goldwind recommended that the current requirement to describe positive to negative sequence ratio should be changed because it varies according to the nature of the fault. Hydro Tasmania considered the requirement should not be applied to synchronous machines or induction machines. TasNetworks noted that care must be taken when specifying reactive current response to negative sequence voltages. Tesla recommended that instead of defining a ratio of negative sequence to positive sequence, [negative sequence] current should be defined in terms of negative sequence voltage. **Revised recommendation** Considering stakeholder feedback, for asynchronous plant, AEMO proposes to revise its Draft Report recommendation to: • Create a “control objective” definition for S5.2.5.5 • Retain in the AAS, 4% and 6% levels for injection and absorption but with the clarification that these levels apply for balanced voltage disturbances. • For unbalanced faults refer to the control objective, considering positive sequence and negative sequence currents. • For unbalanced faults record in the GPS: – The positive sequence reactive current response as a function of positive sequence voltage deviation and ▪ The negative sequence reactive current response as a function of negative sequence voltage, which may be different for different fault types or ▪ The reactive current response on each phase, to phase unbalance, in % current per % voltage deviation, which may be different for different fault types; or ▪ Other relationship agreed with the NSP and AEMO – Priority (active current vs reactive, and/or positive vs negative sequence).

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	resulting in prolonged negotiations on this performance standard. Providing clear technical requirements and assessment criteria will assist with streamlining the connection process.	
Metallic conducting path	**AGL – Support** • AGL supports this amendment. **Amp Power – Oppose (Same as CEC)** • This wording should be retained as the intent is to capture non high impedance faults. Removal of this would likely require the number of assessments to increase. **APD – Support** • APD agrees with the recommendation. **Ausnet – Alternative option proposed** • AusNet cautions on the removal of this term without an appropriate replacement, as on occasion it has been (reasonably) interpreted to mean for GPS and modelling purposes, the residual voltage caused by the applied fault is a constant, as opposed to a variable value (e.g., due to arcing). This aids in setting a reasonable and consistent baseline for assessments to be performed. AusNet recommends replacing the term with a clearer definition of the intent rather than its omission entirely. **CEC – Oppose** • This wording should be retained in that the intent is to capture non high impedance faults. Removal of this would likely require the number of assessments to increase. **CPSA – Oppose (same as CEC)** • This wording should be retained in that the intent is to capture non high impedance faults. Removal of this would likely require the number of assessments to increase. **Energy Queensland – Support** • Ergon Energy and Energex has no objection to removal of this statement. **Hydro Tasmania – Support** • HT supports option 2. **TasNetworks – Support** • TasNetworks supports this proposed change. **Tesla – Support** • Tesla agrees with this deletion and the general comments that it is low importance. **Transgrid – Support** • Transgrid supports Option 2: Removal of NER S5.2.5.5(a) on the basis that existing wording does not appear to add anything useful to the clause.	Responses to the proposal to omit the clause on metallic conducting path were split. AGL, APD, Energy Queensland, Hydro Tasmania, TasNetworks, Tesla and Transgrid supported removing it. Amp Power Ausnet, CEC, CPSA objected to its removal. Amp Power, CEC and CPSA had the same comment about it, that the intent is to capture non-high impedance faults, which AEMO interprets to mean that these respondents considers that the presence of this clause means that high impedance faults would be omitted from the requirement for CUO. Likewise, Ausnet suggests that the intent was to omit faults with variable current (or impedance) from the requirement for CUO. AEMO does not agree with these interpretations, nor does AEMO consider that the absence of the clause would lead to additional studies. A very high impedance fault on the power system is unlikely to trouble a generating system, because, owing to the small impact on voltage, the plant would scarcely detect it. Many faults will be variable in impedance in practice so it would be unreasonable to omit a requirement for CUO on the grounds that the fault had variable impedance. It is noted that there is some justification for not considering risetime and settling time for reactive current injection on faults that are not “step-like”, as these calculations assume the input voltage is a step. AEMO considers the definition was intended to describe faults that included a path through a conductor on the primary plant of the power system, as opposed to a fault on a secondary system. In the absence of this clause, AEMO considers that a power systems electrical engineer reading the fault descriptions would not select any different studies to assess compliance. Based on the feedback it seems that removing the clause would reduce ambiguity about whether a generating system was meant to remain in CUO for some conditions. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation to delete this clause.
Reclassified contingency events	**AGL – Support**	Generating systems and IRS are required under S5.2.5.5(c)(1) to remain in CUO for credible contingency events. However, through a reclassification

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• AGL supports this amendment. **Amp Power – Support** • Amp Power generally support AEMO's recommendation. **APD – issue raised** • APD makes the following observations: – Requiring compliance for a non-credible contingency classified as credible contingency will require further assessments to show compliances, this requirement for NSPs to specify given contingencies as credible should be made to be publicly available information available to all participants at commencement of a project. – If AEMO's recommendations are accepted, NSPs must define the list of reclassed contingencies to be included in the assessments including the reclassed constrained operating conditions (such as reduced generation levels, reduced flow limits etc.,) for each reclassed contingency against which the plant is assessed. **AusNet – Alternative option proposed** • While AusNet understands the issue raised surrounding this item, AusNet has concerns with AEMO's recommendation. – AEMO is responsible for reclassifying credible contingency events under 4.2.3(b). The NSP then uses the AEMO-defined credible contingency event list for the planning, designing, maintaining and operation of the transmission and distribution network. Given that a credible contingency under S5.1.2.1 does not include any additional contingencies (reclassified non-credible events), how can NSPs include any additional reclassified non-credible events for planning, designing, maintaining and operation purposes? We note amendments to Chapter 4 are outside of the scope of this Review. [AEMO Note: this issue is not within scope of this review] – Instead of potentially having an exhaustive list of events captured in its GPS, it may be more expedient to "time-stamp" the agreed credible contingences. For example, if a reclassification of a credible contingency event occurs after the connection agreement has been agreed, and that reclassified credible contingency event is more challenging for the plant to reasonably withstand compared to any other credible contingency event analysed during the connection process, the plant will not be held accountable for being unable to withstand the new reclassified contingency event. **CEC – comment** • Changes to NSP planning / operating philosophy over time could present uncertainty for connecting parties. **EUAA – Support; issues raised** • The EUAA supports AEMO in removing the current situation whereby generators must ride through a non-credible contingency event, even when reclassified as a credible contingency event.	process an event that is not normally a credible contingency can be temporarily reclassified as one. The proposed amendment links the defined credible contingency events to those contingencies that the NSP will normally assess to support the planning of their networks, which excludes those "temporary" credible contingencies identified through reclassification. Most respondents supported the change. AusNet suggested timestamping the credible contingencies for which the plant must remain in CUO. TasNetworks suggested that events reclassified as credible contingencies would be covered under MFRT obligations. CEC commented that changes to NSP planning/operation over time could present uncertainty for connecting parties. In response to APD's concerns, AEMO clarifies that this change would not mean that reclassified events would be included in the assessments. AEMO acknowledges CEC's comment that changes to NSP planning/ operating philosophy over time may present uncertainty for connecting parties. This proposed change does not reduce the uncertainty associated with NSP planning and operation (nor increase it) but does reduce uncertainty and compliance risk associated with reclassification of lines as credible contingencies. AusNet's suggested 'timestamp' approach would reduce connecting parties' risk associated with future changes to the power system but would represent a departure from current practice. The general (undocumented) philosophy that underpins the access standards is that network changes tend to strengthen the power system and should not be detrimental to the performance of generating systems and other connected plant, so that compliance should not be more difficult over time. When other plant connects the intention is that it does not adversely affect the performance of existing plant (reflected in the CUO requirements). The main difference that is occurring now in the power system compared with historical conditions is that fault levels may decline over time due to retirements of large synchronous plant, which may make stability worse. It is this issue that the Review proposes to address with some of the changes to S5.2.5.5 and S5.2.5.13, to improve the long-term performance of the power system. The approach is to require ongoing compliance (including for credible contingency events, the list of which may change over time), but to recognise that settings of controls on the plant might need to change over time. In parallel the system strength rules should limit the extent of changes to system strength over time, so that the impact on compliance is limited, and the changes that could be required to achieve ongoing compliance are also limited. Considering TasNetworks' comments, reclassified events might be considered under MFRT obligations in some cases, depending on the access standard that is agreed, and the nature of the event (e.g. simultaneous loss of two circuits of a double circuit line might or might not form part of MFRT obligations

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• However, the EUAA recommends that further discussion is needed before expanding the credible contingency reference by reference to specify credible contingency events selected by the NSPs. The EUAA considers this is the role of the market operator, AEMO, and not the NSPs. **Hydro Tasmania – Support** • HT supports option 2. **TasNetworks – Comment** • TasNetworks considers that the scenarios a proponent is required to maintain CUO under the MFRT obligation should encompass those credible contingency events of concern. **Tesla – Support, with clarifications** • Tesla supports this change in principle and believes it will provide some helpful market clarifications. However, we would suggest that this list of credible contingency events provided/ selected by the NSPs are as detailed as possible, with a list of specific contingencies provided relevant to the region or connection point, published in NSP's planning report. This information will be helpful. **Transgrid** • Transgrid supports Option 2 to amend the rule to expand the term credible contingency by reference to specify credible contingency events selected by the NSP for the purpose of NER S5.1.2.1.	considering the range of negotiated access standards possible). However, the reclassified contingency combination are considered a single credible contingency event. AEMO agrees with AusNet that the known events at the time of the connection should be reflected in the drafting. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation with the following revisions to: • apply it to both the AAS and MAS; • add requirement to consider commonly reclassified contingencies likely to affect the connection point;. Note that the power system is managed on the assumption that production units will remain in operation for any credible contingency as classified at any time. When a reclassification occurs the AEMO operations will adjust power system conditions so that the power system is operating securely and will land in a satisfactory condition should that reclassified contingency event occur. This can be reflected in a guideline on the assessment process.
NER S5.2.5.7 – Partial load rejection		
Application of minimum generation to energy storage systems	**AGL – Support** • AGL supports this amendment. **APD – Support** • APD agrees with the recommendations. **Ausnet – Support** • Ausnet supports the proposed option. **Hydro Tasmania - Support** • HT supports option 2. **TasNetworks – Support** • TasNetworks supports this proposed change. **Tesla – Support** • Tesla supports this change. **Total Eren – Support** • Total Eren view the proposals to amend S5.2.5.7 as relatively non-contentious and progressed quickly as incremental rule changes.	Respondents generally agreed with this proposed change. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	Transgrid – Support • Transgrid supports the proposed Option 2 to amend the clause to resolve the issues identified.	
Clarification of meaning of continuous uninterrupted operation for NER S5.2.5.7	**AGL – Partly Oppose, partly support** • AGL does not support changing "be capable of" to "remain in" CUO • AGL supports allowing for frequency response, inertial and phase angle response as acceptable responses for this type of disturbance (either in the clause or in the CUO definition. **APD – Clarification requested** • Could AEMO provide further clarity on the opposition to angle jump and frequency change? Normally in a system where a significant amount of load has been lost, the angle and frequency will change (both are linked) and the generators react to these changes through their governing action. In addition to angle and frequency changes, there will be voltage deviations regulated by the voltage controls. Further clarity is requested on how the proposed rule change will impact the assessment requirements. **Ausnet – Support** • Ausnet supports the proposed options 2 and 4. **TasNetworks – Support** • There are several references to "be capable of CUO". For clarity TasNetworks proposes replacing the words "be capable of" with "remain in" for all occurrences within the NER. **Tesla – Support** • Tesla is supportive of this change. **Total Eren – Support** • Total Eren view the proposals to amend S5.2.5.7 as relatively non-contentious and progressed quickly as incremental rule changes. **Transgrid – Support** • Transgrid supports the proposed Options 2 and 4.	Except for AGL, respondents did not oppose Draft Report recommendations. APD requested clarification on what impact inclusion of frequency response and phase angle jump as allowable behaviours would have on assessment requirements. AEMO considers there should be little impact on assessment requirements, assuming the behaviour of the plant is such that it opposes the change in angle and frequency, if capable and enabled (where applicable) for that type of response. TasNetworks noted that there are several "capable of" references that should also be replaced. However, AEMO notes that some of those references were intentional, and refer to facilities that the plant must have, rather than enabled response. That is not the situation in this clause, because the system need is for the capability to be enabled all the time, in anticipation of an event. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation. The reference to inertial, frequency and phase angle jump response is included in the CUO definition.
NER S5.2.5.8 – Protection of generating systems from power system disturbances		
Emergency over-frequency response	**AGL – Support** • AGL supports excluding plant that provides PFR from this requirement • AGL supports taking account of the physical attributes of the plant for the time delay • AGL supports same size threshold for all plant 30 MW **AGL – Oppose**	In the Draft Report AEMO proposed five changes, as follows: • Option 2: Apply the requirement for rapid over-frequency output reduction only if the plant does not participate in primary frequency response (PFR) • Option 3: Change the reference in S5.2.5.8(a)(2)(ii) from "upper limit of the extreme frequency excursion tolerance limits" to "0.5 Hz less than the upper limit of the extreme frequency excursion tolerance limits".

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• AGL opposes changing the "upper limit of the extreme frequency excursion tolerance limits" to "0.5 Hz less than the upper limit of the extreme frequency excursion tolerance limits". AGL suggests it would force some plant off earlier than other plant, which is inequitable. **APD – Support** • Option 2: Some generators conform to Primary Frequency Response (PFR) requirements, but have exemptions from certain performance due to the limitations of their technology type. Any performance criteria considered in S5.2.5.8 that is based upon PFR conformity should also consider the agreed PFR performance or limitations in the technology. An example of how this would be worded might be "Subject to the agreed PFR performance, the generator provides proportional active power reduction etc.," • Agree with other options 3,4, 5 and 6. **Ausnet – Support (other than Option 2)** • AusNet agrees with AEMO's recommendations with the following comments: – Option 2: The PFR deadband and droop are defined for operational requirements but not as an over-frequency protection. It is also not clear generator's PFRR obligation beyond the ± 0.15 Hz threshold where market ancillary services provide the service. AusNet believes that the PFRR is not fully replacing the S5.2.5.8(a)(2) requirements. – Option 3: AusNet supports change of threshold to 0.5 Hz less than the upper limit of the extreme frequency excursion tolerance limits. – Option 4: AusNet supports removal of reference not less than the upper limit of the operational frequency tolerance band. – Option 5: AusNet supports carve out for the 3 sec requirement due to physical limitations (e.g. hydro units to manage penstock pressure). – Option 6: AusNet agrees • Please confirm whether AEMO intends to apply S5.2.5.8(a)(2) to a distribution-connected generator over 30 MW. Currently this sub-clause applies only to transmission-connected projects over 30 MW. **CEC – Oppose option 2, alternative proposed for option 5** • The recommendations to remove paragraph (2) are on the premise that PFR implementation will meet the requirements of this clause. However the PFR implementation would only cover the magnitude of the change (provided a suitable droop setting) and not speed of response as the PFR rate of change is substantially slower than what is required under this clause. Where a generating system implements different (slower) ramp rates for PFR versus S5.2.5.8 (faster), removal of obligations under S5.2.5.8 would not allow for a rapid reduction in active power. • Option 5 – Noting that the current Rules only have a MAS, rather than having a carve-out, suggest an AAS with the 3 second / 50 % reduction and a MAS that doesn't preclude slower units (such as hydro units) from connecting. A NAS would capture performance of units that cannot meet 3 seconds.	• Option 4: Remove the references in S5.2.5.8(a)(2) to "(not less than the upper limit of the operational frequency tolerance band)" • Option 5: Add a carve out for the 3 seconds requirement in NER S5.2.5.8(a)(2)(i)(B) and NER S5.2.5.8(a)(2)(ii), so that where AEMO agrees that the physical attributes of the plant do not allow it to meet the time constraints of these clauses, a longer time can be specified consistent with the fastest active power ramp down rate for safe operation, without being required to disconnect. • Option 6: Apply the same size threshold irrespective of size of plant – 30 MW. For Option 2 the responses were split. Mostly the concerns around option 2 are that PFR does not necessarily fully replace the fast runback solution. AEMO notes that this technically correct, because the Generator or IRS might have negotiated lower requirements for PFR than proposed in AEMO's guideline. Considering that the final PFR requirements significantly relax the response time in some circumstances, AEMO has decided not to proceed with this proposed carve out. For Option 3, AGL opposes the change on the basis that it is inequitable to force some proponents off earlier than others. Other respondents either support it or are silent on it. AEMO notes that the requirement is to reduce output by half at that frequency, and that any plant complying with PFR requirements with droop of 4% or 5% would have reduced their output by more than that at the same frequency. AEMO therefore does not agree that the requirement is inequitable and the current upper limit is unworkable, because it is set at the same frequency at which generating systems are permitted to trip. For Option 4, respondents are either supportive or silent on this issue. For Option 5, most respondents support the proposal, but CEC and CPSA propose establishing an AAS with the current requirement, and a MAS with a lower requirement. The rule does not currently contain an AAS. For Option 6, most respondents either agree with the proposal or are silent. The exceptions are the two respondents from Tasmania – TasNetworks and Hydro Tasmania, who suggest the lower threshold of 5 MW for Tasmania, considering the typical small size of generating units in that region and the small size of the system generally. Considering that some distribution-connected plant might be as large as 200 MW, AEMO has decided to extend the operation of the requirement to distribution-connected plant of 30 MW or more. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to revise the Draft Report recommendation, to:

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	CPSA – Oppose option 2, alternative proposed for option 5 (Same as CEC) • The recommendations to remove paragraph (2) are on the premise that PFR implementation will meet the requirements of this clause. However the PFR implementation would only cover the magnitude of the change (provided a suitable droop setting) and not speed of response as the PFR rate of change is substantially slower than what is required under this clause. Where a generating system implements different (slower) ramp rates for PFR versus S5.2.5.8 (faster), removal of obligations under S5.2.5.8 would not allow for a rapid reduction in active power. • Option 5 – Noting that the current Rules only have a MAS, rather than having a carve-out, suggest an AAS with the 3 second / 50 % reduction and a MAS that doesn't preclude slower units (such as hydro units) from connecting. A NAS would capture performance of units that cannot meet 3 seconds. **EUAA – Support** • The EUAA supports AEMO's proposed amendments to bring the emergency over frequency response in line with the Rapid Frequency Response rules. **Goldwind Australia - Support** • Goldwind support Options 2 and 5. **Hydro Tasmania – Support option 2; alternative option proposed to option 6** • HT support option 2 and then the simplest approach to achieving the intent of this rule clause. • Regarding options 6 and 7 as previously noted a 30MW generator in the region of Tasmania should not be considered as small and that the risk to cumulative exemption of multiple 30MW generators also without PFR could be high without further study / verification of the definition. **TasNetworks – Alternative option proposed to option 6** • As noted above, due to the specific issues in Tasmania, TasNetworks prefers option 6 with the threshold being reduced to 5MW, at least in Tasmania. **Tesla – Support** • Tesla is supportive of this change. **Transgrid – Support, with clarifications** • Transgrid supports Option 2 (disconnecting the generating system within 1 second) to only apply if the generating system does not provide PFR. [Note: This differs from the proposal, which would exclude requirement for reduction as well as when the option to disconnect the plant is selected.] • Transgrid supports Option 3 (0.5 Hz less than the upper limit of the extreme frequency excursion tolerance limit). • Transgrid supports Option 4 (remove the "not less than the upper limit" statement).	• omit option 2 – carve out for plant meeting PFR • redraft the clause with AAS, MAS and general requirements, where proportional response is the AAS requirement, and fast ramp down or tripping are MAS requirements, and negotiation based on longer times than specified is permitted • amend Option 6 to specify a threshold of 7 MW (based on 5% of maximum contingency size) in Tasmania, and 30 MW on the mainland. • Remove references to "transmission-connected" while retaining the size threshold

<table>
<tr><th>Issue</th><th>Schedule 5.2 Generator recommendation feedback summary</th><th>Consideration of issues and revised recommendations</th></tr>
<tr><td></td><td>

Transgrid supports Option 5 (allow for a carve out for the 3 second requirement, where agreed).
Transgrid supports Option 6 (to apply the same size threshold, regardless of technology type).

</td><td></td></tr>
<tr><td colspan="3">NER S5.2.5.10 – Protection to trip plant for unstable operation</td></tr>
<tr><td>Requirements for stability protection on asynchronous generating systems</td><td>
AGL – Partially oppose

AGL does not support inclusion of a detection device requirement in the AAS.

Amp Power – Oppose; Issues raised

Amp Power strongly suggests that more work needs to be done on this clause. (“Many details require further discussion with wider industry:

The nature of data (quantify and frequency of) to be sent to a central system,
Disconnection and reconnection timing and protocol,
Provision of timestamped data to AEMO – it is not clear whether this is in real time or offline (or both). The resolution (and hence quantity) should be clarified as excessive data transfer requirements could adversely affect communications systems, especially if real-time data is required.”)

Automatic disconnection must be treated carefully until such a scheme is proven. An alarm should be raised followed by manual disconnection until need and practicality of an automatic tripping scheme is proven.
Identification of contribution to instability is not a simple exercise and to Amp’s knowledge there is not a proven solution in the NEM (although some are being trialled).

APD – Partially support / alternative option proposed

Issue 1 – APD highlights that recommendation does not cover synchronous generators. The present AAS states the protection must be capable of tripping plant when a condition that would lead to pole slipping. It is not known if such a protection is available and hence we recommend the present AAS should be amended to specify the plant be tripped when a pole slip condition is detected.
Issue 2 - The oscillation magnitude threshold for disconnection should be specified by the NSP.
Issue 6 - It is not clear if the PMU analysis results are to be shared with AEMO in real-time.
APD agrees with MAS recommendations.

Ausnet – Partially support

Issue 1 – Ausnet supports to have facilities to identify instability but highlights the importance of accurate measurements (“Appropriate VTs and CTs” and “monitoring device satisfies the secondary voltage requirement” and “ongoing maintenance plan for equipment calibration”)

</td><td>
The major concerns raised by respondents relate to two issues

The use of a protection system that can automatically disconnect a plant if it experiences oscillations at its connection point.
The requirement for a contribution detection system to identify if the plant is contributing to the oscillations.

Respondents including Amp Power, AusNet, CEC, CPSA, Hitachi, Marinus Link (in regard to a HVDC system), Tesla and Transgrid express concerns about automatic disconnection. Transgrid and AusNet raise concerns about the use of voltage oscillation magnitude as a measure on which to trip a plant. This includes that the sensitivity of voltage to reactive power depends on the fault level (system impedance) so is not a reliable indicator. In addition, the plant may not be the causer of an instability that is present on its connection point, and tripping may cause unnecessary or counterproductive reduction in generation on the power system.
Respondents’ suggestions include:

Ramping down plant rather than tripping them
The NSP to determine the settings for disconnection thresholds
Sending an alarm and then manual tripping being instigated by the NSP
Changing operating mode

Transgrid suggested that only alarming should be enabled until confidence had been gained in any system, to avoid unintended consequences.
Hydro Tasmania suggested that the TNSP should be responsible for the determination and disconnection due to unstable or oscillatory behaviour, whilst the generator should be focused only on the disconnection of plant for asset risk mitigation.
Respondents generally supported the proposal that alternative action to tripping be considered ahead of (or instead of) tripping a plant. Transgrid suggested that automatic tripping should not be required under the MAS.
AEMO acknowledges that setting up an effective automatic protection system would be a complex undertaking that would require careful consideration and co-ordination, and could have adverse impacts if not correctly implemented. Nevertheless, it may be practical for OEMs to design protection for their plant that identifies incorrect operation which results in poorly damped or unstable
</td></tr>
</table>

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Issue 5 – Ausnet does not support 20MW threshold for MAS protection system ("For smaller plant (above 5 MW), it should be up to the NSP to determine on a case-by-case basis.") • Issue 2 – Ausnet supports to take corrective action before tripping • Issue 4 – Ausnet provides consideration on the instability sources ("If magnitude of the oscillation observed is the greatest within a grid region, there is high possibility that plant is the source of the oscillation. However, there is also a great chance that the plant itself is not the causer and it is unfortunately locating at the weakest part of the network with the highest observability. Further actions should be taken, (e.g., If available, enable the use of a Power Operated Device (POD) [rather Power Oscillation Damper? – AEMO note] or, if necessary, gradually reduce the output. – If plant provide negative damping at a certain frequency which is the resonant frequency of the connected grid under some operating conditions and that mode is excited with oscillation observed. – SSR. – Main contributor of an oscillation via online state estimation, dynamic frequency scan, curve fitting to achieve transfer function (derive order of the transfer function by AI learning from enough operating data), participation factor analysis to learn the contribution factor for any potential intra or inter area modes. – SSCI.") **Bo Yin – partially support** • Issue 4 - It might be very difficult or technology impossible for the generating system or IRS to have a detection device to identify whether the production unit or system is contributing to the instability. • Issue 2 - The other options such as taking corrective actions such as ramping down or changing control mode are more feasible. **CEC and CPSA (the same feedback)– issues raised** • Issue 1 – Caution is urged against automatic disconnection. ("An alarm should be raised followed by manual operator disconnection until such a system is proven.) – Trip requirements from AEMO/NSP – speed of trip and what to trip should be clarified. – The 20MW threshold sounds arbitrary, in the context of widespread allocation of 5MW and 30MW thresholds • Issue 4 - Identifying whether a unit is contributing to an instability or not is not a simple exercise and there isn't an accepted solution in the NEM (although some are currently being trialled for certain types of oscillations). • Issue 6 - The nature of PMU data (quantify and frequency of) to be accepted from the central system should be clarified. • Provision of timestamped data to AEMO – it is not clear whether this is in real time or offline (or both). The resolution (and hence quantity) should be clarified as excessive data transfer	behaviour and to disconnect the plant if necessary to eliminate the oscillatory behaviour. AEMO supports providing flexibility in the access standards for actions other than tripping to address the issue, and to allow triggers, thresholds and actions to be agreed with the NSP and AEMO. S5.2.2 would allow these settings, thresholds and actions to be modified over time. Concerns about including a system to identify contribution to an oscillation (raised by AGL, Bo Yin, CEC and CPSA, mainly centre around the immaturity of the technology, the fact that it is not proven and therefore lack of confidence that the requirement can be met. Respondents did not disagree with the merit of such a system were it to operate as proposed. AEMO notes that the ability to differentiate between an oscillatory response that is opposing an external oscillation and one that is caused by an internal instability is very valuable to be able to coordinate appropriate actions to identify and eliminate source of the instability. Other issues: <u>Timeframe of disconnection</u> Some respondents requested more clarity on the timeframe for disconnection. AEMO considers it might be better to maintain flexibility within the performance standard and not be prescriptive about the timing of disconnection, or whether the plant must be disconnected, but in general plant should not be disconnected unless it is causing or contributing to the oscillation. <u>Pole slipping protection</u>: APD suggests, for synchronous generators, changing "lead to pole slipping" to "when a pole slip condition is detected", as detection ahead of pole slipping might not be possible. AEMO considers instability in synchronous machines is not just about pole slipping, even though pole slipping is evidence of major instability. Poorly damped electromechanical oscillations, or voltage control interactions with other plant might also be targeted with this clause. The issue of not having confidence in technology to detect instability ahead of pole slipping is similar to the issue for asynchronous machines, where detection of whether a plant is contributing to or damping an oscillation by countering it is the ideal situation, but not mature technology. Hydro Tasmania suggests that some plant might be permitted to pole slip more than once, without damage. AEMO agrees it is possible for some synchronous machines to recover after pole slipping a small number of times, particularly if operating as synchronous condensers. The current proposal extends pole slipping protection to the MAS.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	requirements could adversely affect communications systems, especially if real time data is required. • Issue 3 - If a reference is made to the PSSG, is there a risk that subsequent changes to the PSSG risk placing generators/IRSs in noncompliance as the reference remains within their GPSs **Energy Queensland – partially support** • Issue 5 - Ergon Energy and Energex are not opposed to the removal of the reference to AS/NZS61000.3.7. However, if this occurs, we suggest a clear definition of stability, and unacceptable oscillations is required. • Issue 1 MAS - We are keen to understand how the threshold of 20MW (for reduced requirements) was determined • Issue 3 - Ergon Energy and Energex support a review of the PSSG and improved clarifications of requirements. **Hitachi Energy – partially support** • Hitachi is concerned that strict adherence to the automatic detect and disconnect rules could cause the detection and disconnection of too many generators. • Hitachi asks for a clear distinction between the AAS and the MAS with regard to the following: "a. detecting an instability, – b. detecting the contribution to the instability, – c. the requirements for a PMU for instability analysis, – d. a system to automatically disconnect the production unit, – e. a system where the NSP or AEMO can disconnect the production unit (remotely), – f. the 30MW threshold for automatic/remote disconnection (does it mean a ≥ 30MW unit, or a unit producing ≥ 30MW?). " **Hydro Tasmania – partially support** MAS: Hydro Tasmania proposes "the MW threshold for exception should be regional based to best manage this risk" but supports a threshold for protection for automatic disconnection. To be proposed by AEMO and the TSNP for agreement with the market participants." • Hydro Tasmania supports the use of alternative control measures (e.g. anti-hunting detection and temporary governor lock) but asking AEMO to establish guidance in relation to (1) what a proposed function would look like and (2) implemented settings as without AEMO / TNSP the connections and compliance costs for generators to determine these addition control functions would disincentivise their inclusion. • HT supports the intent to identify these instabilities and by including the PSSG, a more flexible outcome is allowed for in further refinement to address changing network conditions over time.	It would be possible to amend the proposed MAS to say protection to prevent "sustained pole slipping" which could allow short duration pole slipping. If pole slipping is not sustained, the effect on power quality would be minimal. <u>PMUs and details</u> Some respondents queried the requirement for PMUs. Hydro Tasmania indicated it considers the requirement for a PMU in the AAS an unnecessary cost burden. AMP Power, CEC and CPSA raised concerns about the required level of data transfer and the effect on communications systems, and lack of clarity about whether the data is to be used for offline or real-time purposes. Other proponents such as Tesla and Transgrid supported the provision of PMUs. However, Transgrid notes that some small embedded generation might find it challenging to have communications for remote disconnection. Presumably this would apply for PMU measurement data which has a much higher bandwidth requirement. AEMO considers Schedule 5.2 is not the appropriate place for PMU technical specification but AEMO agrees on the need and benefit in providing more details in guidelines, because the PMUs will need to conform to some minimum common functionality to be useful in a centralised data collection and analysis system. AEMO has proposed a requirement for a PMU for plant of 100 MW or more in the AAS, and with the same threshold in the MAS, but only if required by the NSP. <u>MAS 20 MW level for provision of a protection system to disconnect the plant</u> CEC and CPSA suggested the 20 MW threshold sounded arbitrary and Energy Queensland queried how the threshold was decided. AusNet considers the threshold should be left up to the NSP to decide. Hitachi queried whether it would apply to a unit of 30 MW or a unit producing > 30 MW. AEMO notes that the threshold expressed as [20 MW] in the Draft Report was not fully decided but indicated as a strawman for discussion. Five or 30 MW thresholds, while often used in the rules, have no particular significance other than being "small". AEMO proposes to make this requirement at NSP and AEMO's discretion, and has also proposed that if the plant is not capable of influencing the voltage by more than 1% (under system normal and planned outage conditions) that there not be a requirement for a detection or protection system. <u>Use of the Stability Guidelines</u> Respondents were generally supportive of use of the Power System Stability Guidelines to clarify details relevant to S5.2.5.10. **Revised recommendation** AEMO proposes to revise the Draft Report recommendation as follows:

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• HT proposes inclusion of synchronous generation to the discussion. • ("further amended to allow the detection device to include pole-slip detection for operation once a pre-determined number of pole-slips or power-swings within close proximity to the connection point has been detected by monitoring impedance trajectory. In this regard HT further supports removal of mandatory pre-emptive tripping as currently written. Whilst a generator may choose to implement this to mitigate pole-slip risk to large generators, the decision to do so should be optional (e.g. allow several pole-slip to occur prior to disconnection)." • HT strongly supports the TNSP to be responsible for the determination and disconnection due to unstable or oscillatory behaviour, whilst the generator should be focused only on the disconnect of plant for asset risk mitigation (i.e. pole-slipping or close in power-swings). • Issue 5: HT seeks clarification for proposed requirement and implementation around "capability" for AEMO or NSP to send trip command ("balance capability for AEMO and NSP to trip machines vs stress on generator assets.") • HT does not support compulsory PMUs under the AAS ["concerns with the AAS being too onerous for common recording equipment and imposes an unnecessary additional cost to the generator. **Marinus Link – Support** • MLPL is against the automatic disconnection of HVDC (consequences of a loss of the HVDC system) • MLPL recommends that the "technical requirements for HVDC be specified at a high level only, rather than at the level of detail proposed for generators: – the HVDC system must have facilities in its control system that can detect unstable or oscillatory operation. These detection facilities must be flexible and able to be configured to detect a wide range of instability conditions; – the HVDC system must be able to accept inputs from external sources to signal that an unstable power system condition has been detected and remedial action must be taken – the HVDC system's control system must be flexible and permit customised solutions to be implemented in response to unstable operation. **Total Eren – comment** • Total Eren understands "a longer consultation may be required for more complex clauses (e.g. S5.2.5.5, S5.2.5.8 and S5.2.5.10)." **Tesla – partially support** • Tesla is supportive of the PMU ("We support the recommended requirements around PMUs being connected.") • Tesla is are not supportive of the recommendation made to have capability to disconnect, as automatic disconnection can pose higher system security risk.	AAS for Asynchronous plant • Only disconnect a plant where the plant is contributing to the instability AAS for both synchronous and asynchronous • For asynchronous or synchronous systems of 100 MW rated active power or more, require installation of a PMU with real-time transmission of voltage and current information to AEMO and the NSP • Capability to receive information about contribution from AEMO is also required. MAS for both synchronous and asynchronous plant • Where the plant can cause a voltage change more than 1%, for system normal or planned outage conditions: – Require a system to detect an oscillation in voltage reactive power and active power. – For asynchronous plant, have a process to manage oscillations promptly, which is agreed with the NSP and AEMO – For synchronous machines, a protection system to disconnect the plant for sustained pole slipping if required by the NSP or AEMO • Permit the NSP or AEMO to request proponent to provide a PMU, for systems of 100 MW or more.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Tesla claims that their units very rarely needs to be disconnected and they suggest to replace the disconnection signal with "go to charging mode" signal. "Given the bidirectional nature of battery energy storage systems, there are very few circumstances where a system disconnection will be necessary, if a disconnection or trip signal is sent to generation assets, battery energy storage systems and bi-directional assets could be sent a charge signal." **Transgrid – partially support** • The oscillation magnitude is heavily impacted by the fault level, the lead-lag phase between relevant power quantities, configured droop, ratio and other factors. Therefore, the magnitude of unstable behaviour, that is a relative quantity, cannot be considered as a robust indication or quantity that defines which generator is causing/contributing more or less to the instability or the oscillation. Hence the solution provided to address issue 1 may not be practical to adequately address the issue. One solution to avoid the noted issue is staggering the disconnection between different generators using different disconnection/alarming threshold and contribution criteria(how much in-out of phase behaviour is observed at the time). • Transgrid requests to clarify the meaning of "promptly disconnecting", which can be misinterpreted as "immediately" • Transgrid supports power ramping down option ("ramping down is preferred even if it is a fast ramp rather than trip. This is not contradictory to disconnecting promptly. The generator can ramp down first and disconnect.") • Transgrid notices that dynamic change of a control mode would require "extensive model validation in wide area environment.". Also, they suggest that this should involve all "OEM models support this mode change during the simulation run". • Transgrid requests definition of instability and suggests that S5.2.5.10 could "independently refer to the type of applicable instability for asynchronous generators" and focus on voltage instability ("stable operation of the generator, especially in the context of voltage control which refers to the key context of asynchronous generator under S5.2.5.10, has a clear definition in power system. If the definition of voltage stability is explored in the context of S5.2.5.10, there will be less challenge across the industry for implementing the corresponding protection in a real-time controller.") • MAS: Transgrid supports not requiring contribution detection in the MAS, but in its absence there is a risk of either many generators that either do not take action or disconnecting with no consideration of contribution. Transgrid is of the view that no disconnection must be permitted, in the absence of contribution detection. AAS: Transgrid supports centralised platform for generator disconnection (handled by AEMO). In the absence of such solution, NER shall mandate generator's responsibility under S5.2.5.10. When centralised solution is established, local system could act as a backup.	

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• For the time being, actions limited to alarming only until the confidence in protection systems is built. • Transgrid notes that "for some small projects in embedded networks which are non-scheduled, it may be challenging to have communication facilities that make the remote disconnection possible." • Transgrid supports the requirement for a PMU.	
NER S5.2.5.13 – Voltage and reactive power control		
Voltage control at unit level and slow setpoint change	**APD – Support** • Voltage control at unit level is a good option, however the following points should be considered: • Unlike the synchronous plants, the IBR plants, such as wind farms, can be scattered over a wide area with a different network impedance to the connection point. To achieve a required voltage and reactive support at PoC, different reference voltages need to be applied at each terminal. • Usually in steady state 33 kV reticulation buses will be operated close to 1 pu. The proposed voltage regulation scheme should consider the tap positions of transformers to ensure the desired outcome is achieved. • How to test the controller performance with multiple unidentical inverters? Will performance be assessed at each of the inverters and connection point? When a 5% step change is applied at each of the inverters, how shall the performance at POC be assessed as this response will differ for different plant? **Ausnet – Support** • AusNet agrees with the proposal to allow slow setpoint changes for operational purposes but having ramp limiters disabled during compliance testing (Option 3). • AusNet tentatively agrees with the proposal in Option 2 to allow voltage control for units at their terminals, provided that if the generating system comprises of many smaller generation units, there is sufficient impedance (such as reticulation impedance or step-up transformers) between the unit and a common connection point such that a voltage droop effect can be developed; To prevent interference between the plant/park voltage controller and the unit voltage controllers, it is important to decouple their bandwidths. AusNet's concern is that in distributed generating system, having two or more units in local voltage control mode with insufficient impedance between them may result in potential fighting of units to establish the local voltage. This could occur with both asynchronous and synchronous devices. AusNet has also not analysed this option in the time available so while open to the idea, is not able to definitively provide its support. • AusNet would welcome further analysis, examples and details on the technology types for which this proposal is intended to be applicable. AusNet believes that unit-level voltage	Respondents generally supported the proposed changes. Transgrid suggested splitting the requirements for response to voltage disturbances and response to setpoint changes. AEMO agrees this may be a useful approach especially for plant with fast unit-level voltage control, which may have slower setpoint change response. AEMO will consider this when drafting, to ensure that this solution is permitted. In response to AusNet comments, AEMO notes that voltage control with droop could be implemented on the units, with the control point at a common location, such as the MV bus of a distributed system. This would typically improve sharing of reactive power between the units. AEMO notes CPSA's comments about hybrid plant, and will consider this aspect in the drafting. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation, except that legal advice suggests the current drafting does not preclude unit level voltage control.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	control is acceptable, but whether unit-level current control is appropriate depends on the technology being used. **CEC – Support, with caveats** • Unit level voltage control is seen as beneficial and overcomes some of the challenges associated with plant level control. However it isn't clear how much of an impediment the current Rules actually are given there are generating systems from different OEMs already connected. Hybrid plant (ie wind, solar PV and /or STATCOMs) can also be present and any changes to the rules should not preclude connection of this type of plant. • Slow setpoint change is implemented by some plant and makes practical sense from an operational perspective, however may require additional testing if it is codified. **CPSA – Support, with caveats (Same as CEC)** • Unit level voltage control is seen as beneficial and overcomes some of the challenges associated with plant level control. However it isn't clear how much of an impediment the current Rules actually are given there are generating systems from different OEMs already connected. Hybrid plant (ie wind, solar PV and /or STATCOMs) can also be present and any changes to the rules should not preclude connection of this type of plant. • Slow setpoint change is implemented by some plant and makes practical sense from an operational perspective, however may require additional testing if it is codified. **Goldwind Australia Support option 2; [no comment on proposed option 3]** • Goldwind support Option 2. **Hydro Tasmania – Support** • HT has no issues with proposed amendments as options 2 and 3 are to allow additional control methods and not impose additional control methods in parallel / supplement those already in place (which meet the AAS). **TasNetworks – Support** • TasNetworks supports this proposed change. **Tesla – Support** • Tesla is supportive of this amendment. However, we would suggest that instead of specifying a rate-limit setpoint change, we would recommend also including a low-pass filter as an option. **Total Eren – Support** • Total Eren view the proposals to amend S5.2.5.13 as relatively non-contentious and progressed quickly as incremental rule changes. **Transgrid – Support with clarifications** • Transgrid acknowledges AEMO's point that certain implementations of unit-level voltage control for asynchronous plant can result in interactions with plant level voltage control. It should be noted though, that this interaction isn't inherent to unit level voltage control but is	

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	due the implementation of the internal control system. That is, certain implementations/designs can avoid this interaction. • Transgrid supports Option 2, to amend the S5.2.5.13 to allow for the voltage, reactive power and power factor control to be implemented at the unit level. Typically, Transgrid dictates the normal voltage control strategy for a given project, though this added flexibility in the rules is generally supported. • Transgrid supports Option 3, such that rate-limited setpoint changes can be utilised operationally, though we suggest that consideration be given to including flexibility in the rules to allow for such response, which specifically relate to speed of response. This is in line with the recommendation outlined below. • Transgrid suggests that consideration be given to decoupling the response time requirements for setpoints and disturbances, such that there can be different performance standards for each: – This would help facilitate negotiations for plant which have fast unit level voltage control (for which the performance standard itself can still be assessed at the connection point) and at the same time allowing for longer rise and settling times for plant level setpoint changes. – This also allows for the current rule requirements to still be met where the response to setpoints and disturbances are mostly due to the plant level voltage controls and are thus very similar. – This can also allow for slower responses to setpoint changes whilst allowing for faster responses to disturbances, whether at the plant level or unit level.	
Realignment of performance requirements to optimise power system performance over expected fault level (system impedance) range – Voltage control	**Amp Power – Support** • Amp Power welcome the recognition of aligning performance requirements with the best practical engineering approach. • Amp Power propose the AAS to focus towards both stability and speed of response rather than speed of response only. **APD – Support (partial)** • AEMO recommendations for Options 3 and 7 are agreeable, however it is unclear if option 7 is allowing a GPS to go below a MAS level. • APD propose that the impedances are not to be recorded in the GPS, as these may change over the life of the plant. • Any nearby dynamic reactive plant or generating systems (including asynchronous systems) may influence the response times in practice, so the ability to verify compliance in practice must be considered. APD recommend that these requirements not be overly simplified to be based on fault level alone. • Some NSPs require S5.2.5.13 assessed in PSSE NEM cases. To assess the settling time for maximum system impedance, does it mean the base case need to be tuned with a fault	Most respondents supported the principle of realigning the performance standards to focus more on the higher impedance conditions, where stability is likely to be lower. Hydro Tasmania questioned the proposed use of system impedance rather than fault level. As Hydro Tasmania correctly noted, the use of system impedance here is to do with voltage stiffness. AEMO is not convinced that fault level would give a suitable measure here, as IBR plant tends to have limited fault level contribution, but capable of injecting reactive power up to AAS level around target voltage level. AEMO has proposed use of apparent system impedance, which it explains in the clause. Most of the commentary related to Option 7, which requires settling time to be recorded for typical impedance if the 5 second settling time cannot be achieved at the highest and lowest system impedance. It also relaxes settling time in the MAS, but only if the low system impedance response is over-damped or critically damped. CPSA and CEC noted that disconnecting nearby generating systems can have a similar effect to reducing system impedance.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	level at connection point exactly equal to the maximum system impedance provided by the NSP? **Ausnet – Issues raised; alternative option proposed** • Several of the options presented focus on establishing tuning around higher system impedance. AusNet's view is that tuning to meet timeframes in a high impedance environment equates to a net slowing down of reactive power support overall, and that instead, targeting typical system impedances (as far as practical) and applying 'reasonableness' on assessing plant responses as network impedances vary will yield a better balance between speed and stability (e.g., if the unit has been tuned for typical impedances, we expect to see a faster but more undamped response for high impedances, and a slower but overdamped response for lower impedances). Of course, some wordsmithing would be required to express such 'reasonableness' in the Rules effectively. • Ideally, AusNet would like to see implemented a version of Option 7 [retaining 2 s risetime for high impedance case] but with tuning centred around typical impedances rather than high impedances as currently written. If this is not possible, the need to vary the target impedance for tuning (i.e., low, typical, high) should be determinable on a case-by-case. **Bo Yin – Issues raised** • It is worth discussing how to specify one droop gain of the voltage control to cover the large range of system impedance. • It is worth discussing whether one set of control parameters is expected for the whole range of system impedance or a set of control parameters for the weakest grid? **CEC – Support; issue raised** • The proposed approach of tuning for the highest system impedance makes sense. However, it should be noted that an adjacent generator that normally operates in voltage control mode being taken offline (or changing control modes) can have a similar effect to reducing the system impedance. Similar to a new plant connecting adjacent to an existing plant in voltage control which can reduce the rise time of the existing plant. It isn't clear how changes to other plant / addition of new generating systems will be managed. **CPSA – Support; issue raised (Same as CEC)** • The proposed approach of tuning for the highest system impedance makes sense. However it should be noted that an adjacent generator that normally operates in voltage control mode being taken offline (or changing control modes) can have a similar effect to reducing the system impedance. Similar to a new plant connecting adjacent to an existing plant in voltage control which can reduce the rise time of the existing plant. It isn't clear how changes to other plant / addition of new generating systems will be managed. **Hydro Tasmania – Support, with clarification; issue raised** • HT supports options 3 and 7 in principle, however HT would like to seek confirmation if possible that the highest and lowest system impedance level are to be taken as at the time	AEMO agrees that the presence of nearby plant can affect the performance, particularly for reactive power risetime. AEMO experience is that settling time of 5s is less sensitive than risetime and can usually be achieved over a range of power system conditions. Adding another plant nearby can make the response to a voltage disturbance faster and less stable because nearby plants respond in the same direction to a voltage disturbance and the response to a setpoint change slower as the nearby plants oppose the change in voltage. When distributed plants have voltage response at unit level, they may oppose the change in voltage requested by a central controller requesting a setpoint change. This also has the impact of making setpoint reactive power risetime slower than response to disturbances. The reactive risetime for setpoint change is not always a good indicator of the reactive risetime for voltage disturbance, and the response to a disturbance may be faster and less stable. This suggests that targeting 2 s rise time for a setpoint change might not be an appropriate objective. The risetime requirement should be better targeted to a step change in the power system voltage, which would more appropriately consider the effect of other plant on the stability of the combined system. The main disadvantage of this as a compliance measure is the difficulty in testing it. This might be resolved by testing the reactive power rise time for compliance with the model but assessing the risetime for a 5% step of voltage through simulations. Smaller voltage disturbances could also be compared with model response to provide confidence in the model. Additionally, a plant that has a 2 second risetime for a 5% voltage disturbance should also meet that requirement for smaller disturbances as long as the signal to noise ratio is sufficient for calculation of risetime, so partial compliance can at least be tested. Note that the simulation would need to include nearby plant which will affect the result. Nearby plant will also affect the testing of reactive power step, so the modelling of nearby plant needs to be reasonably accurate. Transgrid suggested: • Providing flexibility for longer settling times in the MAS. • Not carving out a significant range of conditions under which the performance is undefined. • Transgrid also suggests decoupling the voltage disturbance and setpoint settling times. AEMO notes this is not precluded as part of a negotiation.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	of application / commissioning and that future changes in network do not necessitate revisiting. • HT is aware that system impedance is used in this section to describe the system electromagnetic strength or voltage stiffness. Compared with the conventional measurement - fault level, HT would believe that the system impedance has below shortfalls: – 1) Disregards the system voltage amplitude impact. – 2) Hard to reflect the fault level contribution from the GFM and need to distinguish GFM and GFL sources. – 3) The IBR virtual impedance could be a variable. • Hence, HT would like to clarify the intent of introducing system impendence in this section. **TasNetworks – Support** • TasNetworks supports this proposed change. **Tesla – Support with clarification** • Tesla accepts the majority of proposed changes in respect of system impedances. • We would suggest that it would also be valuable for AEMO to consider aligning the approach taken for rise time and settling time with different rise times specified for into a limit (proposed 4 second) and not into a limit (2 seconds as per the AEMO proposed amendment). • In respect of the proposed amendments to the MAS – would AEMO consider replacing the settling times with a requirement to be adequately damped. **Total Eren – Support** • Total Eren view the proposals to amend S5.2.5.13 as relatively non-contentious and progressed quickly as incremental rule changes. **Transgrid – Alternative option proposed** • Transgrid believes that the amendments proposed in Options 5, 6, and 7 relating system impedances and the requirements for rise and settling times are more appropriate as general guidelines for a negotiated standard. This will help generating systems better tune their plant and provide evidence for their performance standards, whilst not carving out a significant range of operating conditions for which the performance standards are undefined. • Defining performance standards only for very specific network conditions will not provide clear metrics for commissioning and ongoing compliance. It will likely add further complexity to the performance standards and connections process (this is especially true for Option 7) and thus contradicts one of the key objectives of this review which is to streamline the connection process. Meeting the objective of “aligning with best system performance” is believed to be better served by reinforcing the negotiating framework and general guidelines. • Transgrid recommends consideration be given to providing flexibility in the MAS for settling times to be agreed to a longer value, with agreement between AEMO and the NSP. This	**Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the draft proposal, with the following revisions: • In the AAS, change the rise time requirement to a rise time for a voltage disturbance of up to 5% of 2 s for the range of system impedance conditions between maximum and typical system impedance. • In the MAS, the NSP and AEMO may agree a longer settling time. • The NSP is to advise the low, high and typical apparent system impedance value. **Note** The concept of **apparent system impedance** relates to the impedance at operating voltages as opposed to the equivalent impedance level that would be calculated considering short circuit condition, which is more commonly understood. The apparent system impedance would give the same dV/dQ and dV/dP at the connection point, as would be measured with dispatch pattern including inverter-based plant online and in their normal operating configuration. The difference between traditional system impedance and this approach will be greatest with very high IBR penetration electrically close to the connection point. As noted by some consultation respondents, electrically close generation affects the measured reactive power response to a voltage disturbance, and the reactive power response to a voltage setpoint change. AEMO invites specific feedback from stakeholders on this concept and its application to this performance standard.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	flexibility is in line with the draft determination by the AEMC for the S5.2.5.5 MASs (Efficient reactive current access standards for inverter-based resources). • As per the comments above in Section 3.10.1 (Voltage control at unit level and slow setpoint change) where Transgrid recommends that the settling time requirements be decoupled for setpoints and disturbances, this added flexibility can better facilitate the negotiation process whilst also achieving good power system performance outcomes.	
Materiality threshold on settling time error band and voltage settling time for reactive power and power factor setpoints	**AGL – Support** • AGL supports the proposed options. **Amp Power – Support** • Amp Power support AEMO's recommendation. **APD – Support; issues raised** • APD supports the proposed options. • AEMO recommended Options 2 and 3 do not address the issue of the network disturbances on the settling time calculated signals. For example, a voltage step change test could trigger a nearby filter or reactor switching which leads to a secondary disturbance and subsequently longer settling time. Under such circumstances the study results with such secondary disturbances should be excluded from the settling time compliance assessments. **Ausnet – Support** • Ausnet supports the proposed options 2 and 3. **CEC – comment** • Note that PF step tests can also require steps to P (not only PF), in which case settling time for P may require assessment. **CPSA – Comment** • Note that PF step tests can also require steps to P (not only PF), in which case settling time for P may require assessment. **Hydro Tasmania – Support** • HT supports options 2 and 3. **TasNetworks – Comment** • It may be unduly burdensome to measure the response of Q control and power factor control but if used they must be stable, e.g. provide an adequately damped response. **Tesla – Support with clarification** • Tesla would suggest a slight amendment to the AEMO wording such that the "change in active power is less than 5MW or less than 2% of the plant rating. Whichever is the highest." **Total Eren – Support**	Respondents other than Transgrid supported the proposal to remove the requirement for assessing voltage settling time for reactive power and power factor steps. AEMO agrees with TasNetworks that any mode of operation must be adequately damped. Transgrid preferred to retain voltage settling time for reactive power and power factor setpoint change, with discretion to exempt voltage from the assessment. AEMO notes that it proposes to remove the requirement for assessment of settling time for reactive power and power factor setpoint changes for secondary operation modes. This means that in practice the application will only apply to a small proportion of connections. However, in principle, voltage is not the controlled variable, even in the example provided of a switched reactive component, so there should not be a requirement to assess its settling time. If the voltage settling time is poor, but not paralleled by a poor settling time of reactive power, this might be a result of an external source of the problem, rather than a compliance issue with the plant under test. When the plant is in reactive power mode or power factor mode, it will not attempt to control the voltage, which may be noisy or even oscillatory. That is not an indication that the plant is the cause of the problem. It is only in simulation with single machine infinite bus modelling where there is no background voltage variation and there is necessarily a direct relationship between the voltage and the reactive power (or power factor) output. For Option 3 which proposed a materiality threshold for active power settling time for voltage steps and voltage setpoint steps, respondents generally supported the concept of a threshold for active power settling time. Transgrid and Tesla proposed alternative options. Transgrid proposed that the threshold be proportional to plant size but have a cap of 5 MW. Tesla also suggests a threshold proportional to size of plant, but with a floor rather than a cap: the higher of 5 MW and 2% of the plant rating. A 2% criterion would mean that a plant of 1000 MW would not be assessed for a change in active power of less than 20 MW, leading to a +/- 2MW error band, with the current definition of settling time. The purpose of AEMO's proposed change is to avoid the calculation where it is not meaningful because of the size of the error bands, but is also intended to reduce compliance burden for small plant.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Total Eren view the proposals to amend S5.2.5.13 as relatively non-contentious and progressed quickly as incremental rule changes. **Transgrid – Alternative proposed** • Transgrid agrees with AEMO's view that for small variations in active power in response to a voltage step, the assessment of settling time for active power is no longer meaningful. Transgrid also supports the view that consistency and clarity are important for these assessments. • In Transgrid's experience, plant do not normally exhibit issues meeting the settling time requirements of voltage for reactive power / power factor step tests. There can be instances though, where auxiliary reactive power plant can be switched to provide reactive power feedback support to achieve the setpoint. This switching can result in voltage transients which might be better assessed from looking at the voltage settling time, rather than reactive power itself. • Summary of Transgrid Position – Regarding Option 2, Transgrid's preference would be to retain the requirement to assess the settling time for reactive power and voltage for both reactive power and power factor step tests, with a potential amendment to the rules such that where the NSP and AEMO agree, the voltage can be exempt from the assessment. – Regarding Option 3, the application of materiality thresholds to active power should be dependent on plant size. For small generator connections, the proposed threshold of 5 MW is not appropriate as active power variations/oscillations could occur below this threshold. It is recommended that the threshold be based on a percentage of the generator's capacity, with a cap at 5 MW (for example). This value can be specified in the performance standards as part of the general requirements.	Considering the first objective, AEMO's view is that error bands below +/-0.25 MW would not be meaningful. As part of this rule change AEMO is also considering a change to the settling time definition to: ***settling time*** In relation to a *control system*, the time measured from initiation of a step change in an input quantity to the time when the magnitude of error between the output quantity and its final settling value remains less than 10% of: (a) if the sustained change in the quantity is less than half of the maximum change in that output quantity, half of the maximum change induced in that output quantity; or (b) otherwise, the sustained change induced in that output quantity. This change is to make a smooth transition between the size of error bands for transient and sustained changes. A side effect of this proposed change is that the error band for a transient change (ie for part (a) of the definition), is halved. With this change in definition a 3 MW change would lead to a band size of ±0.15 MW. AEMO considers an error band of less than ±0.5MW could suffer from noise, but a threshold of 10 MW would be too high. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation with the following revisions to: • Apply a materiality threshold not requiring calculation of settling time for active power excursions of less than 3MW generally, and • Apply a settling time error band that is the larger of ±0.5 MW and the value calculated under the settling time definition, for voltage steps in any mode or setpoint change in voltage control.
Clarification of when multiple modes of operation are required	**AGL – Support** • AGL supports the proposed option. **APD – Support** • APD agrees with the recommended option. **Ausnet – Support** • Ausnet supports the proposed option. **CEC – Support; issues raised** • Limitation of control modes to one or two, a primary and secondary is generally welcome.	Respondents generally supported the proposal for a primary and secondary operating mode in the AAS. CEC and CPSA commented that it isn't clear what the assessment requirements will be (simulation and/or testing). AEMO notes that assessment requirements do not normally form a part of access standards. CEC also raised that most NSPs require three modes. AEMO intends that this should be reduced to two modes by this proposal. CEC raised that in some cases it may not be possible to stably tune a secondary control mode. AEMO suggests this would be very rare, but were it to occur, a negotiated access standard near minimum might be possible.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• It isn't clear what AEMO is proposing in terms of assessment requirements (simulations and/or testing) and this should be clarified. • Some members also raised the point that most NSPs will require voltage control as the primary mode, power factor control mode for operation, reactive control mode for testing and commissioning. In which case it was it does not appear much will change with this rule – in most cases, three control modes may still invariably be required. • Members also raised that in some cases it may not be possible to stably tune a secondary control mode and that this should be considered. **CPSA – Support; issues raised** • Limitation of control modes to one or two, a primary and secondary is generally welcome. • It isn't clear what AEMO is proposing in terms of assessment requirements (simulations and/or testing) and this should be clarified. **Hydro Tasmania – Support** • HT supports option 2. **TasNetworks – Support** • TasNetworks supports this proposed change. **Tesla – Support** • Tesla is supportive of the reduced assessment requirements. **Total Eren – Support** • Total Eren view the proposals to amend S5.2.5.13 as relatively non-contentious and progressed quickly as incremental rule changes. **Transgrid – Partial Support; Alternative option proposed** • Transgrid supports the intent of Option 2, that is, to have a primary and secondary control mode. Though it should be at the NSP's discretion as to what the primary mode is, as this might not always be voltage control, as stipulated in Option 2. There should be flexibility in the rules to accept/specify other primary control modes as a part of the AAS. • Transgrid prefers that the requirement for settling time should be retained in the AAS for reactive power and power factor control modes and thus, the secondary control modes. The setpoint performance can relate closely to the response to a voltage disturbance, therefore there is merit to keeping it as a directly testable and controllable performance criterion.	Transgrid requests flexibility to accept or specify primary control modes other than voltage as part of an AAS. Transgrid does not explain why this needs to be part of an AAS. Transgrid prefers that settling time [for set point change] be retained in the AAS for reactive power and power factor as secondary modes. Transgrid states that the setpoint performance can relate closely to the response to a voltage disturbance. AEMO's view is that reactive power and power factor set point step changes provide little value for actual operation, as performance criteria. However, there could be value in testing to compare the modelled and simulated values for the purpose of model verification. This does not need to rely on a compliance requirement for setpoint change settling time, but would be a model validation test (which is outside of the scope of this review) **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.
Impact of a generating system on power system oscillation modes	**AGL – Support (partial)** • AGL supports carving out the MAS for system strength-sensitive oscillations, where the generator has elected to pay for system strength mitigation. **Amp Power – clarity required on option 2**	Most respondents either supported or were silent on the proposal that a new plant connecting to the power system should not make existing poorly damped modes worse. Transgrid raised a concern that carving out the requirement in the MAS for damping of system strength related oscillations for plant that elects to pay the system strength charge would allow poorly tuned IBRs to be connected. However, AEMO notes as the plant needs adverse system strength impact

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	• Amp Power propose that more clarity and certainty should be provided on the need for system strength-sensitive oscillation damping and developing controls to damp such oscillations **APD – issues raised (option 2)** • Following comments are made in regard to the recommended Option 2: – Option 2 AAS requires the plant to have stabilisers that are capable of providing positive damping and is silent on the enablement of such device. – The option is also silent on the acceptable level of positive damping by the stabiliser. – Usually, the stabiliser will be designed to target a particular range of frequency where the damping will be effective. However the power system is expected to have both low frequency (from traditional plants) and high frequency (from IBRs) modes. To manage these extremes it will be a challenge for the POD design. Alternatively, it will be possible to have gain roll off above certain frequencies, however this approach may not meet the positive damping provision requirement. – It is understood that in Option 2, NSPs will advise the mode frequencies over which positive damping is expected. Following the rule amendments AEMO's guidelines will be required on the assessment methodology for this clause. – AEMO is requested to consider these practical issues while finalising on Option 2. **Ausnet – Issues raised/ alternative option proposed (option 2 only)** • While AusNet agrees that it is necessary to consider additional damping requirements for contemporary or emerging oscillation types due to high IBR penetration, AusNet is concerned that the proposed changes may be too vague to be adequately set and enforced. Moreover, it is worth noting that electromechanical and intra-regional oscillations may not be entirely absent from the system even with an IBR-dominated generation fleet, given that many synchronous condensers have already been deployed in the grid for system strength purposes. If this trend continues, potentially undamped electromechanical oscillations will also continue to occur. • AusNet acknowledges that it is challenging to get the balance right, but in general would support a bolstering/addition to the standards to capture the oscillations that an IBR-dominated system may experience, rather than a replacement of existing wording with less specific requirements. **CEC – oppose option 2 only** • More clarity and certainty should be provided on the need for system strength-sensitive oscillation damping and developing controls to damp such oscillations. As mentioned by AEMO, this area is still evolving. However the concern is when such a requirement is mandated for the sake of it (as per the NER) with no proper assessment or testing of the damping controls. Either during the modelling phase or during commissioning. Hence resulting in costs to OEMs, generators and consumers for a function that is not utilised resulting in 'gold plating' of the network.	mitigated, by definition it will not meet this clause as it stands. Otherwise it would not pay the TNSP but would self-mitigate. To address Transgrid's concerns, AEMO proposes to keep the requirement, but make it subject to consideration of the performance required from the SSSP under S5.1.14. (Similar wording to S5.2.5.5 (r1).) This should apply to both the MAS and AAS. Option 2 raised concerns from a number of respondents including Amp Power, APD, Ausnet, CEC and CPSA, whereas Hydro Tasmania, TasNetworks, Total Eren and Transgrid supported the proposal. The concerns raised were about the requirement being too vague or lacking clarity and certainty, in the light of an area that is still evolving. Tesla suggested that critical modes be identified through the NSP's system studies and published in the planning report. After further consideration, AEMO has come to the view that, while the objective of better damping of system strength sensitive modes of operation is desirable, achieving effective damping might require coordinated response from multiple plants, in which case it is difficult for this to be a compliance requirement within a GPS of an individual generating system or IRS. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain option 2 revise the Draft Report recommendations to: • exclude Option 2; • amend Option 4, replacing it with a requirement for assessments to consider the required performance from the system strength service provider at the relevant system strength node.

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
	CPSA – oppose option 2 only (same as CEC) • More clarity and certainty should be provided on the need for system strength-sensitive oscillation damping and developing controls to damp such oscillations. As mentioned by AEMO, this area is still evolving. However the concern is when such a requirement is mandated for the sake of it (as per the NER) with no proper assessment or testing of the damping controls. Either during the modelling phase or during commissioning. Hence resulting in costs to OEMs, generators and consumers for a function that is not utilised resulting in 'gold plating' of the network. **Hydro Tasmania – Support** • HT supports options 2, 3 and 4 **TasNetworks - Support** • TasNetworks supports this proposed change. **Tesla – Support with clarification** • Critical fault of oscillation required by the NSP. Critical modes need to be identified though NSP's system studies. The system study results, including critical faults, system conditions, and oscillation modes should be published in NSP's planning report. Similar to the credible contingency event recommendation above. **Total Eren – Support** • Total Eren view the proposals to amend S5.2.5.13 as relatively non-contentious and progressed quickly as incremental rule changes. **Transgrid – Partial Support; Oppose option 4** • Transgrid supports Option 2, to require facilities capable of providing positive damping for critical modes of oscillation. However, we have concerns with identification and provision of critical modes of oscillations being part of this clause requirement given that: – the critical oscillation modes can change with the addition of the connecting plant. – the critical oscillation mode can change over a period of time. – critical modes of oscillation can be inter-area oscillations where the NSPs may not have visibility into ongoing connections in a different region and their impacts on the oscillation modes. • Regarding Option 3, is the intention to retain current requirement under clause S5.2.5.13 (d)(1)(ii) while incorporating Option 3 to the MAS? Transgrid supports retaining some level of tolerance as in the current rule requirements for S5.2.5.13 (d)(1)(ii). • Transgrid does not support Option 4. Oscillations sensitive to system strength can still be improved by plant tuning and functionalities such as inverter level voltage control. While it is the obligation of the SSSP to provide system strength to the required level, electing to pay the system strength charge should not allow poorly tuned IBRs to be connected, which does not align with promoting efficient investment as per the NEO.	

Issue	Schedule 5.2 Generator recommendation feedback summary	Consideration of issues and revised recommendations
Definition – continuous uninterrupted operation		
Recognition of frequency response mode, inertial response and active power response to an angle jump	**AGL – Support** • AGL supports amendments that would recognise inertial and primary frequency response in the CUO definition • Prefers modification in the CUO definition over modification in each clause. **Amp Power – Support** • Amp Power welcome AEMO's review of the CUO definition. **Ausnet – Support** • AusNet supports AEMO's proposal for either Option 2 or 3, whichever is more expedient. **CEC - Support** • The CEC welcomes AEMO's review of the CUO definition and looks forward to reviewing the approaches to S5.2.5.1 & S5.2.5.4 in particular. **CPSA – Support (Same as CEC)** • The CEC welcomes AEMO's review of the CUO definition and looks forward to reviewing the approaches to S5.2.5.1 & S5.2.5.4 in particular. **TasNetworks – Support** • These features can benefit the power system so a change to CUO definition should be allowed, as long as the inclusion of such features are included in the relevant clauses of the agreed GPS. **Tesla – Support** • Tesla is supportive of this change. **Transgrid – Support; Issue raised** • Transgrid supports Option 2, that is, to modify the definition of CUO to allow greater flexibility in the types of acceptable responses. • In addition to Option 2, if there was a specific requirement not captured in the updated definition for CUO in the glossary, then this could be captured for that applicable clause. • Transgrid has seen issues with application of CUO requirement in paragraph (d), when considering inadvertent disconnection scenarios (classified as credible contingency events under S5.1.2.1) for assessing feasibility of transfer trip schemes under clause S5.2.5.8(d). This issue is exacerbated by the lack of clarity in the system standards under clause S5.1a.4 on the allowable reduction in voltage of supply at a connection point because of a contingency event. • In Transgrid's view, there should be flexibility for the NSP to allow transient voltage variations below 90% of normal voltage for a limited period due to inadvertent disconnection of transmission plant, provided that there are no material adverse impacts to other connected plant.	Respondents generally support the proposed change to include reference to inertial response, primary frequency response and phase jump response in the continuous uninterrupted operation clause. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.

3 Feedback on Schedule 5.3a Conditions for connection of MNSPs

Issue	Schedule 5.3a HVDC recommendation feedback	Consideration of issues & revised recommendations
NER S5.3a.1a Introduction to the schedule		
Alignment of schedule with plant-type rather than registration category	**EUAA [support]** • EUAA understands that HVDC connections will become more commonplace (through interconnectors and offshore wind farms) and provision of their own registration category will allow AEMO to better manage the technical performance and their contribution to system security and operation of the market. • EUAA supports AEMO's proposed alignments of HVDC connections with the connection requirements for generators through Schedule 5.2 with respect to reactive power, voltage disturbances, frequency disturbances, fault ride-through requirements and monitoring and control requirements. **Marinus Link – Support** • Marinus Link is supportive of performance standards applicable to HVDC systems in general. • Whilst Marinus does not consider the current Rules requirements to be unworkable, we acknowledge that the lack of clarity could lead to protracted negotiations and consequent project delays. The existence of access standards for HVDC systems has the potential to alleviate this situation. Marinus considers that the current arrangements can be made to work. • For TNSPs: Schedule 5.1 applies. Whilst not originally envisaged, many aspects of Schedule 5.1 can be applied to HVDC systems but the requirements are not specified in sufficient detail for HVDC systems so the outcome relies on agreement between relevant TNSPs, via the joint planning framework. Marinus Link is evidence that the TNSPs can progress HVDC systems under the current Rules framework. • For Generators: Schedule 5.2 applies. The majority of requirements in Schedule 5.2 could apply to an HVDC system on the Generator's side of the connection point. • For Designated Network Assets, the functional performance would be specified by the primary TNSP. The lack of clear HVDC performance standards may prove problematic if the primary TNSP and the Designated Network Asset developer disagree, noting that the joint planning process does not apply. • Note that "extensive drafting and detailed consideration of consequential amendments", as well as "clarification of the application of standards that involve the agreement or	AEMO agrees with Marinus Link that NER S5.1 was originally designed to apply to regulated AC network businesses (TNSPs and DNSPs). Further, AEMO considers that HVDC systems should be exempt from the requirements of NER S5.1. This is because: • Parts of NER S5.1 apply to an NSPs obligations when a network user connects. In this context a HVDC system would be that connecting network user. • Parts of NER S5.1 are superseded by the proposed HVDC access standards which are generally more arduous, or no less arduous. • While Directlink and Murraylink are now operating as regulated HVDC systems they were initially designed and commissioned as MNSPs under the requirements of S5.3a. The advantages of exempting HVDC systems from NER S5.1 include: • Making the requirements for a TNSP owned regulated HVDC system consistent with an equivalent MNSP HVDC system. • Removing any potential ambiguity between S5.1 and S5.3a. AEMO agrees with Marinus Link that harmonic filters connected elsewhere in the AC network may be more effective than filters at the connection point, and that it may be more efficient to delay the connection of filters in some cases if harmonic distortion issues emerge after the commission of the HVDC system. AEMO considers that this may also apply to some IBR generator or load connections. AEMO also considers that this inefficiency should be able to be avoided for regulated HVDC systems through the joint planning process. AEMO does not agree with Marinus Link that regulated HVDC systems should not be required to meet the system strength requirements in S5.3a.7. That is, AEMO considers that HVDC systems should be capable of operating for SCR less than 3.0, which AEMO understands is well within the capability of all modern HVDC systems. However, AEMO does agree with Marinus Link that system strength charges should not apply to HVDC systems developed by regulated NSPs. Rather the need for additional system strength services, or

Issue	Schedule 5.3a HVDC recommendation feedback	Consideration of issues & revised recommendations
	approval of the NSP in cases where the NSP itself is the operator of the relevant plant" for syncons should also apply to HVDC access standards. • A simple change to the applicability of S5.3a may have unintended consequences: • If owned by the TNSP, is the TNSP also required to comply with S5.1? – Some parts of S5.1 only applicable to AC (e.g. unbalance) – Some can be applied to HVDC in a general sense (e.g. stability) – Some can be applied equally (e.g. frequency variations) – Need to consider conflicts – S5.1 could be reframed to only apply to AC networks. Alternatively a case by case exemptions for HVDC from S5.1. • The application of S5.3a to regulated may lead to a less efficient outcome if an issue can be solved elsewhere in the AC network, potentially at a later date. For example harmonic filters at the terminals versus in the network. • An HVDC system owned by a TNSP should not pay for system strength services (like a Statcom wouldn't). Thus, the joint planning process would be best to deal with this issue. • Transitional arrangements should be included in the draft rule for consultation. Marinus Link is well advanced and likely to have connection agreements before the recommended changes take effect. Marinus is concerned if there is a delay and additional requirements were imposed at the last minute. The key point is that it is not appropriate to consider that solar, wind or battery inverters can inherently provide similar performance to VSC HVDC systems on the basis that the same principles apply to both. • Marinus Link disagree with the statement that "The VSCs used for modern HVDC systems operate with the same principles as the VSCs used in solar, wind and BESS". They note that the inverters are different, using modular multi-level convertor (MMC) technology. • To effectively support timely integration of HVDC systems, the proposed HVDC access standards must be set at levels that manufacturers can readily meet with their standard design offerings. At times of supply scarcity, manufacturers have less incentive to create bespoke solutions for particular projects. Requiring negotiation may also cause cost and delay. **TasNetworks – Support** • TasNetworks supports the broad principle of applying Schedule 5.3A on the basis of plant type rather than registration category. There are some concerns that a blanket application may have unintended consequences and urge AEMO to consider whether the same standards should apply to all HVDC connections or whether some variation in standards depending on circumstances should be incorporated into Schedule 5.3A. **Tesla – Support** • Tesla is supportive of this change.	the allocation of existing system strength services, and the recovery of the associated costs would be determined through the joint planning process. AEMO agrees with Marinus Link that transitional arrangements are required so that existing and committed HVDC systems are not captured by the recommended changes to the access standards. AEMO notes Marinus Link's observation that modern HVDC systems use modular multi-level convertor (MMC) technology that utilises high speed switching of capacitors, rather than the PWM inverters used in solar, wind and BESS. AEMO considers that the main difference is how the converters generate the AC voltage sine waves rather than the converters' ride through capability. AEMO does not anticipate this would have a material impact on the performance of the HVDC system, other than for harmonics. AEMO does not agree with Marinus Link and TasNetworks that the AAS for HVDC systems should be less arduous to reduce the need for negotiation. The negotiation costs and delays for more arduous AAS are equivalent to the costs and delays for IBR generating systems generally. Therefore, AEMO does not recommend making the AAS for HVDC systems less arduous than that required for generating systems. While this may lead to faster negotiations, an HVDC system should be required to meet the AAS if it is capable and a less arduous performance would reduce system, security. In addition, it would be hard to justify a less arduous AAS for HVDC systems compared to the AAS for generators. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation with the following revisions to: • Define HVDC systems (as 'schedule 5.3a plant) and apply the requirements of Schedule 5.3a to all to HVDC systems irrespective of registration classification. • Exclude HVDC systems from the requirements of NER S5.1 where they have performance standards documented under Schedule 5.3a. AEMO notes that current and committed HVDC projects will not be affected by the recommended changes to the HVDC access standards.

<table>
<tr><th>Issue</th><th>Schedule 5.3a HVDC recommendation feedback</th><th>Consideration of issues & revised recommendations</th></tr>
<tr><td>Application of NER S5.3a to HVDC systems connecting remote generation, including offshore wind</td><td>Marinus Link – raised issue
• Where an HVDC systems connects an AC system that is for generation only (e.g. a REZ), then the performance standards that matter are only at the connection point to the primary TNSP. The following aren’t important in the remote AC system:
– reactive power capability of the WTGs, synchronous condensers and offshore HVDC converter;
– quality of electricity generated at the offshore AC bus;
– voltage and reactive power control of the generating units and synchronous generating units;
– frequency control of generating units;
– frequency operating standards (does not need to be 50 Hz system)
• Any performance of the offshore plant that is more costly than the minimum performance required to ensure adequate performance at the connection point would not support the NEO.</td><td>AEMO understands that several offshore wind generation facilities are being contemplated and that these facilities may require HVDC technology.
AEMO agrees with Marinus Link that it may not necessarily be efficient to impose the NEM frequency, voltage and power quality standards within the wind generation facility. Rather, bespoke standards or arrangements within the facility may be more effective.
However, the configuration and commercial arrangements for these potential future generation facilities are still evolving, making it impossible to be sure that the recommended access standards and associated NEM frameworks will be appropriate for all potential eventualities. Rather, when the future configurations and commercial arrangements are sufficiently evolved then potential NER changes and derogations should be considered as required.
AEMO’s recommended amendments to NER S5.3a apply to HVDC systems interfacing with one or more alternating current networks (or parts of an alternating current network). In the case of an offshore wind facility, the requirements of the amended NER S5.3a would only need to apply at the connection to the main shared network.
AEMO also notes that frameworks for offshore transmission are still in development and the technical requirements may be regulated in alternative ways, including potentially as part of a generating system.
Revised recommendation
Considering stakeholder feedback, AEMO proposes to amend the Draft Report recommendations to:
allow flexibility for the performance requirement within an offshore wind facility.</td></tr>
<tr><td colspan="3">NER S5.3a.8 – Reactive power capability</td></tr>
<tr><td>Reactive power</td><td>EUAA – Support
• EUAA supports AEMO’s proposed alignments of HVDC connections with the connection requirements for generators through Schedule 5.2 with respect to reactive power.
Marinus Link – Alternative option proposed
• Understands that a power factor of 0.95 (or 32.9% of rated active power) is standard for VSC HVDC systems.
• MLPL supports the following changes to reactive power capability recommended for generators, and considers these should also be made applicable to HVDC systems:
– reduction of reactive injection capability at voltages above a nominated threshold and reduction of reactive power absorption capability at voltages below a nominated threshold; and</td><td>AEMO notes Marinus Link’s comment that HVDC systems usually have a capability of approximately 33%, compared to the 39.5% requirement for the AAS, however, AEMO considers that means HVDC systems are expected to be capable of exceeding the MAS by a substantial margin. If it is necessary the HVDC system could install additional reactive plant if it is required to meet the AAS. Therefore, there is no reason to change the recommendations for the AAS or the MAS.
AEMO agrees with Marinus Link that the temperature de-rating of reactive power capability should be consistent with the requirements for generators in S5.2.5.1.
Revised recommendation
Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.</td></tr>
</table>

Issue	Schedule 5.3a HVDC recommendation feedback	Consideration of issues & revised recommendations
	– temperature de-rating of reactive power capability aligned with temperature re-rating of active power capability.	
NER S5.3a.13 – Response to disturbances in the power system		
Voltage disturbances	**EUAA – Support** • EUAA supports AEMO's proposed alignments of HVDC connections with the connection requirements for generators through Schedule 5.2 with respect to voltage disturbances. **Marinus Link – Support**	Both the EUAA and Marinus Link agreed that the voltage disturbance ride through requirements for HVDC systems should be consistent with the access standards in NER S5.2.5.4 for generating systems. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.
Frequency disturbances	**EUAA – Support** • EUAA supports AEMO's proposed alignments of HVDC connections with the connection requirements for generators through Schedule 5.2 with respect to frequency disturbances. **Marinus Link - alternative option proposed**: • the AAS for HVDC systems remains unchanged, that is, to remain in CUO for power system frequency within the frequency operating standards; and • a MAS for HVDC systems be established, based on the MAS in S5.2.5.3.	AEMO considers that the alternative proposed by Marinus Link to apply the requirement in NER S5.1.3 for TNSP equipment to operate indefinitely within the *extreme frequency excursion tolerance limits* and the proposed AAS in the Draft Report are in effect broadly equivalent. This is because operation within the *extreme frequency excursion tolerance limits* (and outside the *operational frequency tolerance band*) would only occur for a few minutes before many generators and loads disconnected, leading to a major supply disruption. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.
Fault ride through requirements	**EUAA – Support** • EUAA supports AEMO's proposed alignments of HVDC connections with the connection requirements for generators through Schedule 5.2 with respect to fault ride through requirements. **Marinus Link – Support** • recommends AEMO give consideration to whether it is necessary to exempt TNSP owned HVDC systems from the requirements of S5.1.9.	Both the EUAA and Marinus Link agreed that the fault ride through requirements for HVDC systems should be consistent with the access standards in NER S5.2.5.5 for generating systems. AEMO notes that Marinus Link considers that a TNSP owned HVDC system should be exempted from NER S5.1.9. This is consistent with AEMO's view that HVDC systems should be exempted from all the requirements of NER S5.1. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation and additionally: • require HVDC systems to inject or absorb reactive current during the fault (consistent with s5.2.5.5 requirements for generating systems).
NER S5.3a.4 – Monitoring and control requirements		
Remote monitoring and protection against instability	**EUAA – Support**	AEMO notes that Marinus seems to have only considered cases where there are no interactions with other control systems. AEMO considers that such interactions are possible in the future and monitoring of HVDC system stability should be integrated into the AEMO systems.

Issue	Schedule 5.3a HVDC recommendation feedback	Consideration of issues & revised recommendations
	• EUAA supports AEMO's proposed alignments of HVDC connections with the connection requirements for generators through Schedule 5.2 with respect to monitoring and control requirements. **Marinus Link– Supports with alternative option proposed** • Expects instability issues for HVDC systems will be studied on a case-by-case basis, therefore recommends that the technical requirements for monitoring and protection against instability for HVDC be specified at a high level only, rather than at the level of detail proposed for generators. Critical items to be specified include: – the HVDC control systems must have facilities to detect unstable or oscillatory operation, which must be flexible for a wide range of instability conditions – the HVDC control system must be able to accept inputs from external sources to signal that an unstable power system condition has been detected and remedial action must be taken – the HVDC system's control system must be flexible and permit customised solutions to be implemented in response to unstable operation.	**Revised recommendation** Considering stakeholder feedback, AEMO proposes to revise the Draft Report recommendation as follows: AAS: • A requirement to install a PMU at each connection point • The capability to detect instabilities and execute hierarchy of automated actions agreed with the NSP and AEMO to supress instabilities; • The agreed hierarchy of automatic actions may include the protection system disconnecting the HVDC system if required by AEMO or NSP but should only be triggered when all other measures have been taken and the HVDC system is contributing to the instability; • If required, HVDC system to have capability to send information from the detection system to AEMO and NSP, • If required, HVDC system to have capability to receive remote tripping signal from NSP; • If required by AEMO, capability to receive information from AEMO about plant's contribution to instability; MAS: • A requirement to install a PMU, if requested by the NSP • The capability to detect instabilities and execute hierarchy of actions to supress instability that is agreed with the NSP and AEMO • If required, the capability to send information from the detection system to AEMO and the NSP • If required by NSP, the capability to receive remote tripping signal from NSP • A requirement for detecting the contribution to instability is not required.
New standards		
Voltage control	**Marinus Link – Support** • Supports a "primary" mode being voltage control, and a secondary mode being either reactive power control or power factor control, with reduced assessment requirements for the secondary mode.	The only respondent on this issue, Marinus Link, supported the proposed change. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.
Active power dispatch	**Marinus Link – Supports with alternative option proposed** • An inherent feature of HVDC systems so there is no reason to oppose such a recommendation or need to mandate it.	AEMO agrees that active power control is an inherent feature of HVDC systems. AEMO also agrees that the active power of an HVDC system could be determined by frequency control or phase angle control systems but the

Issue	Schedule 5.3a HVDC recommendation feedback	Consideration of issues & revised recommendations
	• Rather than be dispatch directly by NEMDE, an HVDC system could mimic the operation of an AC Interconnector by generating a dispatch target internally based on frequency or phase angle.	current process of dispatching the NEM HVVDC systems directly from NEMDE works well. It optimises the HVDC active power transfer without limiting the ability to install additional frequency control functionality, such as the Basslink frequency controller. AEMO considers that adopting an alternative approach to control the active power transfer on an HVDC system would require further consideration before it would not be appropriate to specify any requirements ion the access standards at this time. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.

Multiple schedules

Issue	Multiple schedule recommendation feedback	
NER Multiple clauses		
References to superseded standards	**AGL – Support** • AGL supports amendments to remove reference to superseded standards. **Ausnet – Oppose** • The Draft Report appears to be concerned with two issues: – Industry uncertainty about whether an IEC technical report (which is informative) can or should replace an approved AS/NZS standard (which is normative) – Confusion caused by the application of clause 1.7.1(i) of the NER in determining which version of standard applies. • In respect of the first issue, we agree with AEMO that further consideration should be given to whether informative technical reports should form the basis of binding obligations on Registered Participants, particularly in circumstances where non-compliance with those obligations can lead to compliance and enforcement action. • In respect of the second issue, we do not see how the effect of clause 1.7.1(i) is impacted by whether or not the date of a standard or technical report is included, or how omitting the date operates to alleviate any such confusion. Therefore, we invite AEMO to reconsider the need for this proposed amendment. **Marinus Link – Support** • AGL supports amendments to remove reference to superseded standards. **Hydro Tasmania** • HT supports option 3. **TasNetworks – Support**	Respondents other than Ausnet supported the proposed change. AEMO notes that: • At present there is considerable confusion about which standard applies, with many NSPs requiring the 2012 version even though it is informative rather than normative. This is the outcome from application of clause 1.7.1(i) but it is unclear from that clause whether an informative standard can replace a normative one, without the standard being explicitly identified. • Removing the date and changing the name from AS/NZS 60000.3.6.2001 to IEC 60000.3.6 would remove the confusion that currently exists. • AEMO does not agree with Transgrid that a clarifying statement is needed, because a reasonable person seeing a standard without a date, in relation to a current requirement, would apply the current version. The issue of normative versus informative does not arise with the flicker standard. However, the confusion that having the date included causes still arises, because, although NER 1.7.1(i) is clear in this case, it is not well

Issue	Multiple schedule recommendation feedback	
	• TasNetworks supports amending the references in S5.1.5, S5.1.6 S5.1a.5 and S5.1a.6 to the latest versions without dates. **Transgrid – Support with clarification** • Excluding the dates from the references to the relevant standards could result in different versions of the standard being used across the industry. Noting that NER 1.7.1(i) may not be widely known in the industry, if dates are excluded from the reference, a clarifying statement should be included to indicate that the latest version of the standard is referred.	known in the industry that the rule provision exists. Removing the date makes it clear that the current version is applicable. **Revised recommendation** Considering stakeholder feedback, AEMO proposes to retain the Draft Report recommendation.