AEMO

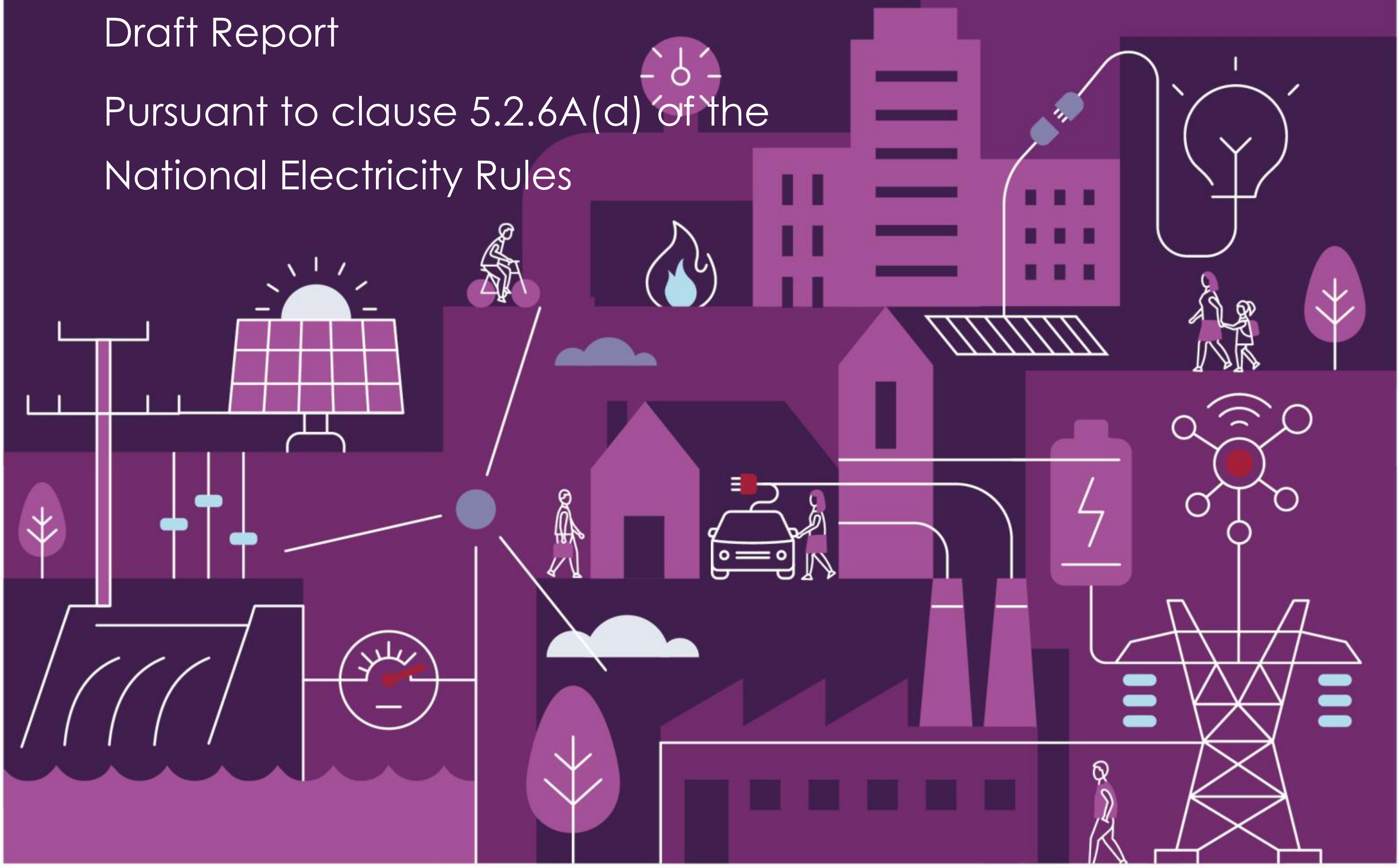
AUSTRALIAN ENERGY MARKET OPERATOR

AEMO review of technical requirements for connection under Schedules 5.2, 5.3 and 5.3a of the National Electricity Rules

3 March 2023

Draft Report

Pursuant to clause 5.2.6A(d) of the National Electricity Rules



Important notice

Purpose

This draft report is published in accordance with clause 5.2.6A(d) of the National Electricity Rules, as part of AEMO's periodic review of the technical requirements for connection in the National Electricity Market.

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Executive summary

This draft report presents AEMO's consideration and initial recommendations on changes to the National Electricity Rules (NER) technical requirements for connection in the National Electricity Market (NEM).

It is part of a review (Review) that AEMO must conduct, pursuant to clause 5.2.6A(a) of the NER, at least once every five years.

The NER requires the Review to consider some or all of the technical requirements set out in Schedule 5.2, Schedule 5.3 and Schedule 5.3a and assess whether those requirements should be amended, having regard to the following criteria (review criteria):

- the national electricity objective (NEO);
- the need to achieve and maintain power system security;
- changes in power system conditions; and
- changes in technology and capabilities of facilities and plant.

AEMO initiated the Review with the publication of an approach paper[1] in October 2022, which identified a number of key considerations. The recommendations in this draft report have been developed after extensive engagement with a broad range of stakeholders, including technical focus groups comprising representatives of network service providers (NSPs), market participants (generators and large customers), project developers and original equipment manufacturers (OEMs). AEMO is grateful for their time and valuable contributions to this Review to date, and looks forward to ongoing constructive engagement in the next phases.

Context

The Australian power system and the broader Australian economy are in a period of rapid transition, with far-reaching impacts on the operation of the power system. The changes encompass the composition of the power system's generation fleet, the nature of its loads, and the technologies employed both within networks and connected plant. AEMO's approach to the Review aims to support the energy transition to a reliable power system based on renewable energy sources, whilst ensuring that the future power system can be operated securely, and is sufficiently resilient to extreme conditions.

Draft report documents

This draft report is published in two parts:

- This document, the primary draft report, including AEMO's recommendations for amendments to NER Schedule 5.2 (Conditions for connection of Generators and Integrated Resource Providers) and Schedule 5.3a (Conditions for connection of Market Network Services).
- An addendum to the draft report, to be published shortly after the primary draft report, setting out AEMO's recommendations for amendments to NER Schedule 5.3 (Conditions for connection of Customers).

[1] AEMO review of technical requirements for connection (NER clause 5.2.6A), at https://aemo.com.au/consultations/current-and-closed-consultations/aemo-review-of-technical-requirements-for-connection.

This decoupling of customer issues from the requirements for generation (including integrated resource systems [IRS][2]) and market network services reflects the additional work required to develop technical requirements appropriate to address emerging and future issues associated with large loads of a diverse and changing nature, where the current requirements are very limited.

Objectives and recommendations

AEMO recommends amendments to the NER to address 44 issues raised in relation to Schedule 5.2 and Schedule 5.3a.

As a whole, AEMO's Schedule 5.2 recommendations seek to achieve the following high-level objectives, developed with regard to the review criteria:

- Broaden application of technical requirements to synchronous condenser connections.
- Align with best power system performance.
- Streamline the connection process.
- Reorient to best power system performance.
- Support efficient investment.
- Improve power system resilience.
- Remove inadvertent impediments to the connection of grid-forming inverters that may provide beneficial capabilities.

It is noted that, for the connection of GFM technology, AEMO has focussed its Review recommendations on amending or adapting relevant technical requirements to ensure they do not inadvertently hinder its connection and the beneficial capabilities it might provide. AEMO acknowledges the importance of further work to develop core requirements to support the connection of GFM technology and will therefore consider whether there is a need for further amendments to the technical requirements of NER Schedule 5.2, following this Review.

Schedule 5.3a recommendations seek to meet the following high-level objectives, which have regard to the review criteria:

- Broaden the application of technical requirements to all high voltage direct current (HVDC) system connections.
- Incorporate and expand technical requirements to appropriately account for the impact and capability of HVDC systems.

The tables below summarise AEMO's recommendations for amendments to the technical requirements set out in Schedule 5.2 and Schedule 5.3a.

[2] The assessments and recommendations in this draft report have been based on the NER requirements including the changes made by the National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021.

Table 1 Schedule 5.2 Conditions for Connection of Generators recommendations

Issue	Schedule 5.2 Generator Recommendation
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	Replace all the references to Generators or Integrated Service Providers in NER Schedule 5.2 with another defined term (e.g. connected participant or Registered Participant), to apply the schedule more generally, with appropriate interpretation clauses to confirm the meaning of the term in the context of the schedule[3]. Corresponding changes may be required elsewhere in the NER, to the extent the access standard schedules and associated performance standards are referenced elsewhere in Chapter 5 or in other defined terms 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, with a list of exceptions also specified in NER S5.2.1.
NER S5.2.5.1 – Reactive power capability	
Voltage range for full reactive power requirement	Modify the AAS to include a voltage-dependent requirement for reactive power: • Limit the requirement for full reactive power capability to a 10% voltage band around a centre point nominated by the NSP. • For voltages within the 10% voltage band, require 0.395 x Pmax reactive injection and absorption. • For voltages below the 10% voltage band down to 90%, require 0.395 x Pmax reactive injection. • For voltage from the lower limit of the 10% voltage band to 90%, the requirement for reactive absorption decreases linearly with decrease in voltage from -0.395 x Pmax to 0 MVAr. • For voltages above the 10% voltage band up to 110%, require 0.395 x Pmax reactive absorption. • For voltage above the upper limit of the 10% voltage band to 110%, reactive injection reduces linearly from 0.395 x Pmax to 0 MVAr.
Treatment of reactive power capability considering temperature derating	Clarify that for the purpose of NER S5.2.51, the rated active power or rated maximum demand must take account of the temperature dependency of the rating, and that the required Qmax and Qmin are functions of Pmax as derated. That is, Qmax (T) = 0.395 Pmax (T), and Qmin (T) = -0.395 Pmax(T) for operating temperature T at the connection point, for reactive power absorption. Require the performance standards to document: • Active power derating of production units as a function of temperature, if any. • Reactive power derating as a function of temperature of production units and any other reactive power facility, if any. • Maximum operating temperature and minimum operating temperature of the generating system or IRS. • Maximum operating temperature for which the plant is not derated. • Reactive power performance requirement as a function of active power at the connection point at the maximum temperature for which the plant is not derated. • Reactive power performance requirement as a function of active power at the connection point at the maximum operating temperature, where different. • Reactive power performance requirement at the connection point as a function of temperature.
Compensation of reactive power when units are out of service	Amend as follows: • Remove requirement to restrict the reactive range where the voltage impact of the generating system or IRS with units not in service is less than a voltage threshold (to be defined). • Where the Generator or IRP and the NSP agree to limit the range of reactive power at the connection point by means of a subset of production units operating in voltage, reactive power or power factor control, compliance is assessed as if the control is a secondary mode of operation under S5.2.5.13. • Maximum active power consumption of a generating system or integrated resource system in respect of auxiliary load and the range of permitted reactive power at the connection point to be specified as steady state values.

[3] Including the application of the schedule to exempt participants where clause 5.3.4A (proposal and negotiation of access standards) extends to those parties under the Chapter 5 connection framework.

Issue	Schedule 5.2 Generator Recommendation
S5.2.5.1, S5.2.5.5, S5.2.5.7, S5.2.5.8, S5.2.5.10	
Simplifying standards for small connections	Amend as follows: • S5.2.5.1 AAS: Set the reactive power required for injection and absorption to be the lower of 0.395 x Pmax and the reactive power that would give rise to a [5%] voltage change, for generation connected to a distribution network. • S5.2.5.5 AAS, MAS: Exempt synchronous and asynchronous generating systems and IRS less than [30] MW connected at MV or LV level, from assessments related to reactive current injection. • S5.2.5.7 AAS, MAS: Exempt generating systems and IRS less than 30 MW from this clause in both automatic and minimum access standards. • S5.2.5.8 MAS: See the related proposal for this rule. • S5.2.5.10 See the related proposal for this rule. • In the definition of AEMO Advisory Matters, exclude connections less than 30 MW.
NER S5.2.5.2 – Quality of electricity generated	
Reference to plant standard	Remove reference to AS1359.101(1997) in respect of a synchronous generating unit as a plant standard for harmonic voltage distortion.
NER S5.2.5.4 – Generating system response to voltage disturbances	
Overvoltage requirements for medium voltage and lower connections	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, and amend S5.2.5.4(c) to a threshold consistent with the largest generator contingency in the region.
Requirements for overvoltages above 130%	AEMO recommends that risk to generators of this clause be bounded. Given the complexities of the issue, AEMO is seeking input from its stakeholders into the most appropriate method of addressing this issue, which may be one of the identified options or an alternative.
Clarification of continuous uninterrupted operation in the range 90% to 110% of normal voltage	Specify that for the purposes of NER S5.2.5.4(a)(6) subject to energy source availability, reactive capability must be maintained, and active power not materially reduced, for voltages in the range 90 to 110% of normal voltage for voltage variations up to 10% within 5s, within the reactive power range and voltage range specified in S5.2.5.1.
NER S5.2.5.5 – Generating system response to disturbances following contingency events	
Definition of end of a disturbance for multiple fault ride through	Specify that the end of a power system disturbance, for the purpose of multiple fault ride through (MFRT) assessment, is the time when, following fault clearance, the voltage recovers to and remains within the range 90 to 110% of normal voltage at the connection point for at least [20ms].
Form of multiple fault ride through clause	Amend as follows: • A suite of tests, established by AEMO, incorporating the MFRT requirements under the AAS and MAS. • A requirement on the proponent to apply the tests considering the range of fault levels nominated at the connection point by the NSP, and using the site-specific settings proposed for the plant. • A requirement on the proponent to declare in proposed performance standards any impediment to MFRT, and provide evidence to support the declaration. • A requirement that compliance with the performance standard is to be demonstrated by performance against the test suite and, throughout the life of the plant, not tripping for any undeclared impediment, checked by verifying the cause of any applicable trips during multiple disturbance events.
Number of faults with 200 ms between them	Retain for the MAS, up to six faults and 200 ms and combination but allow specific limitations such as technology-related limitations (but not limitations arising from inadequate tuning) to be carved out of these requirements for modelled and non-modelled limitations. This allows flexibility while minimising the carve outs from present requirements. It also promotes efficient connection as it can be programmed into the proposed common test suite.
Reduction of fault level below minimum level for which the plant has been tuned	Amend as follows: • Carve out from the MFRT conditions for continuous uninterrupted operation (CUO), in both the AAS and MAS, conditions where fault levels fall below the lower bound of the fault level range for which the plant has been tuned. • Require that the range of fault levels for tuning be advised by the NSP and recorded, along with (but not within) the performance standards

Issue	Schedule 5.2 Generator Recommendation
	• Enable the NSP to require retuning of the plant, where changes to fault level on the power system could cause the plant to be unable to remain in continuous uninterrupted operation for multiple disturbance.
Active power recovery after a fault	Change the AAS, substantially consistent with the MAS changes, subject to minor amendments proposed by AEMO in response to the ERC0272 draft determination. In the final report for this Review, consideration will need to be given to how AEMC's final determination deals with frequency response, inertial response and active power response to phase angle changes.
Rise time and settling time for reactive current injection	Amend as follows: • Omit settling time for the AAS. • Replace adequately damped with adequately controlled. • Qualify that rise time is to be measured for "step-like" voltage profile at the production unit terminals. • Add a commencement time requirement, less than 10 ms, with response in a direction that opposes the change in voltage at the production unit terminals.
Commencement of reactive current injection	Specify that reactive current response to an undervoltage event commence above 85% of normal voltage at the connection point, and for an over-voltage event commence below 115% of normal voltage at the connection point.
Clarity on reactive current injection volume and location and consideration of unbalanced voltages	Amend as follows: • Clarify that the GPS should record the capability provided by the facilities and the settings for reactive current injection that are implemented. • Clarify that the settings should be set to minimise the voltage deviation on each phase from its pre-disturbance value, subject to maintaining stable operation over the expected range of system impedance levels. • Require that the reactive current injection capability be assessed for positive sequence values. • Require documentation of the negative phase sequence injection.
Metallic conducting path	Remove NER S5.2.5.5(a) on the basis that existing wording does not appear to add anything useful to the clause.
Reclassified contingency events	Expand the credible contingency reference by reference to specify credible contingency events selected by the NSP for the purpose of NER S5.1.2.1 (credible contingency events).
NER S5.2.5.7 – Partial load rejection	
Application of minimum generation to energy storage systems	Amend the clause to refer to generating units for the carve out about operating above minimum generation.
Clarification of meaning of continuous uninterrupted operation for NER S5.2.5.7	Replace the term "be capable of" with "remain in".
NER S5.2.5.8 – Protection of generating systems from power system disturbances	
Emergency over-frequency response	Amend as follows: • Make paragraph (2) apply only if the plant does not provide primary frequency response consistent with the Primary Frequency Response Requirements (published under NER 4.4.2A), considering deadband and droop. • Change the reference 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". • Remove the reference from "not less than the upper limit of the operational frequency tolerance band". • Add a carve out for the 3 seconds requirement in (a)(2)(i)(B) and (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 rules, a longer time can be specified consistent with the fastest active power ramp down rate for safe operation. • Apply the same size threshold irrespective of nature of plant – 30 MW.

Issue	Schedule 5.2 Generator Recommendation
NER S5.2.5.10 – Protection to trip plant for unstable operation	
Requirements for stability protection on asynchronous generating systems	In the AAS, specify that a generating system or IRS, for its asynchronous units: • Must have a protection system that can detect an instability and disconnect the production unit based on its nominated settings such as disconnection time and oscillation magnitude. • May take corrective actions such as ramping down or changing control mode (where the thresholds and corrective actions, are to be coordinated by the NSP). • The generating system or IRS must have a detection device to identify whether the production unit or system is contributing to the instability or (subject to the agreement of the NSP and AEMO) a PMU connected to the unit or system capable of providing information to a central system to identify if the unit or system is contributing to an instability. Where a central system is used, the generating system or IRS must have the capability to accept information on contribution from the central system. • The generating system or IRS must have a PMU, regardless of whether a centralised system for determining contribution to an oscillation is used. The PMU would need to monitor and analyse the active power, reactive power and voltage at the plant, and provide the results to AEMO and the NSP. The MAS, for a generating system or IRS [20 MW] or more, would require: • For generating systems or IRS greater than 20 MW, its asynchronous units, a protection system to disconnect for instability or sustained oscillatory response in active power, reactive power or voltage. • For its synchronous units, to have a protection system to disconnect a synchronous generating unit for pole slipping. • Have capability to accept a trip command from AEMO or the NSP In the MAS, • Require a monitoring system for active power, reactive power and voltage, capable of providing timestamped data to the NSP and AEMO. • Not require a detection device to identify whether the production unit or system is contributing to the instability. • Remove reference to AS/NZS 61000.3.7:2001 from the MAS. In addition, remove to AS/NZS 61000.3.7:2001 from the MAS.
NER S5.2.5.13 – Voltage and reactive power control	
Voltage control at unit level and slow setpoint change	Amend as follows: • To clarify that voltage, reactive and power factor control may be implemented at production unit level, for both synchronous and asynchronous plant. • Specifically allow rate-limited setpoint change of the generating system. Bypass rate limiting during testing to assess stability of the controls. The changes would apply to both synchronous and asynchronous plant. The slow setpoint change amendment would apply to voltage, power factor and reactive power modes.
Realignment of performance requirements to optimise power system performance over expected fault level (system impedance) range – Voltage control	Require that the range of system impedances for which the plant is tuned be recorded in the releasable user guide. In the AAS: • Require a 2 second rise time of reactive power for a 5% setpoint change for the highest system impedance level nominated by the NSP. • Retain a 5 second settling time (5% step not into a limit) and 7.5 s settling time (5% step into a limit). In the general requirements: • Where 5 second settling time cannot be met at both minimum and maximum system impedance, control tuning should be set to achieve AAS level settling time for maximum system impedance and target as close to AAS level settling time as possible for highest system impedance, and settling time for low, typical and high system impedances to be recorded in the GPS. • The typical system impedance level should be reflective of typical dispatch levels. • Similar clarifications as those proposed for the general conditions for voltage control, should be applied for reactive and power factor modes where settling time cannot be met at minimum and maximum system impedance conditions with the same control tuning settings. In the MAS:

Issue	Schedule 5.2 Generator Recommendation
	• Retain settling times as per existing MAS for highest system impedance level. • Allow a higher settling time for lowest system impedance level, provided the response is critically- or over-damped. • Where the MAS settling time cannot be met at both highest and lowest system impedance, settling times for highest, typical and lowest impedances are to be recorded in the GPS. In addition, apply the same approach to the synchronous machine requirements for settling times only (as there is no rise time requirement for synchronous generating systems).
Materiality threshold on settling time error band and voltage settling time for reactive power and power factor setpoints	Amend as follows: • Remove the calculation of voltage settling time for reactive power and power factor modes. • Assessment of active power settling time is not applicable for voltage, voltage setpoint, reactive or power factor steps when the maximum change in active power is less than 5 MW.
Clarification of when multiple modes of operation are required	Require two modes in the AAS: • With the ability to switch between them • Where primary mode is voltage control • Where secondary mode either power factor or reactive power • With reduced assessment requirements for secondary mode: – remove the requirement for settling time compliance assessment for power factor and reactive power setpoint changes – retain the requirement for settling time assessment for voltage disturbances.
Impact of a generating system on power system oscillation modes	Amend as follows: • Modify the AAS to require facilities capable of providing positive damping for system strength-sensitive critical modes of oscillation identified by the NSP. • Modify the MAS to require it not to exacerbate any mode of oscillation beyond the point at which it would be adequately damped or to exacerbate any oscillation that is not adequately damped. • Carve out the damping requirements of MAS (d)(1) pertaining to system-strength sensitive oscillations (only) where the Generator or IRS has opted to pay for system strength services to be provided by a SSSP.
Definition – continuous uninterrupted operation	
Recognition of frequency response mode, inertial response and active power response to an angle jump	Modify the CUO definition or relevant clauses to: • Permit responses opposing voltage phase angle jumps and frequency changes, including inertial response during disturbances, in clause (b). • Permit inertial response and response opposing voltage phase angle jumps and inertial response, after clearance of any fault, in clause (c). • Take into account inertial response and response to voltage phase angle jumps for subsequent response, in clause (d).

Table 2 Schedule 5.3a Conditions for connection of MNSPs recommendations

Issue	Schedule 5.3a HVDC Recommendations
NER S5.3a.1a Introduction to the schedule	
Alignment of schedule with plant-type rather than registration category	Apply the requirements of Schedule 5.3a to all to HVDC systems irrespective of registration classification.
NER S5.3a.8 – Reactive power capability	
Reactive power	Align the reactive power capability requirements for HVDC systems with those for generators in NER S5.2.5.1, noting the proposed changes to NER S5.2.5.1 for generating systems.

Issue	Schedule 5.3a HVDC Recommendations
NER S5.3a.13 – Market network service response to disturbances in the power system	
Voltage disturbances	Align the voltage disturbance power capability requirements for HVDC systems with those for generators in NER S5.2.5.4, considering the proposed changes to NER S5.2.5.4 for generating systems discussed in this report.
Frequency disturbances	Align frequency disturbance power capability requirements for HVDC systems with those for generators in NER S5.2.5.3, including the RoCoF requirements, noting the proposed changes to NER S5.2.5.3 for generators discussed in section 4.5 of this report. Exempt NSPs from the requirement of NER S5.1.3 to align with the recommended requirements for all HVDC systems.
Fault ride through requirements	Align fault ride through and MFRT capability for HVDC systems with those for generators in NER S5.2.5.5, noting the proposed changes to NER S5.2.5.5 for generating systems discussed in this report.
NER S5.3a.4 – Monitoring and control requirements	
Remote monitoring and protection against instability	Align remote monitoring and protection against inverter instability requirements for HVDC systems to the equivalent requirements for generating systems in NER S5.2.5.10.
New standards	
Voltage control	Align AC voltage control capability for HVDC systems with those for generators in NER S5.2.5.13, noting the proposed changes to NER S5.2.5.13 for generating systems discussed in this report.
Active power dispatch	Align active power control requirements for HVDC systems with those for generators in NER S5.2.5.14, including for dispatch and ramping.

Table 3 Multiple Schedules recommendations

Issue	Multiple schedule Recommendations
NER Multiple clauses	
References to superseded standards	Amend the references to AS/NZS 61000.3.6 and AS/NZS 61000.3.7 (with or without dates) in S5.1.5, S5.1.6 S5.1a.5 and S5.1a.6 to the latest versions TR IEC 61000.3.6 and TR IEC 61000.3.7, without dates.

Next steps

AEMO invites submissions on this draft report from interested parties. **Please provide submissions by 5.00 pm AEST on 20 April 2023 to contact.connections@aemo.com.au.** Any inquiries and/or meeting requests should also be directed to the same email address.

AEMO intends to publish all submissions on its website. Please identify any part of your submission that is confidential, which you do not wish to be published. Respondents should note that if material identified as confidential cannot be shared and validated with other interested persons then it may be accorded less weight in AEMO's decision-making process than published material. AEMO prefers that submissions be forwarded in electronic format in order to be published on the AEMO website.

Prior to the submission deadline, AEMO will hold a public forum on the draft report on 12 April 2023, with the time of the forum to be notified closer to that date.

Prior to publishing the final report, currently expected in October 2023, AEMO intends to undertake a further round of consultation to seek feedback on a draft of amended rules arising from the recommendations. The draft amendments will incorporate feedback from consultation on the draft report. While not a requirement under NER 5.2.6A, AEMO considers that obtaining this feedback is an important step to optimise drafting of any rule change request arising from the Review, and to inform a decision on whether to request 'fast track' consideration of any changes.

The following table contains indicative timeframes for the Review.

Table 4 Timeframes for Review

Activity	Timing
Approach Paper released	12 October 2022 (complete)
Draft Report (Part 1) published	3 March 2023 (complete)
Draft Report (Part 2) addendum published	Late March 2023
Information forum	12 April 2023
Draft Report (Part 1) consultation closes	20 April 2023
Draft Report (Part 2) addendum consultation closes	30 business days from publication
Draft Rules consultation commences	May-June 2023 (indicative timing)
Final Report released	October 2023
AEMC formally notified of outcomes	November 2023 (indicative timing)

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1 Introduction

The National Electricity Rules (NER) require AEMO to conduct a review of some or all of the technical requirements of Schedules 5.2, 5.3 and 5.3a at least once every five years to assess the need for amendment. This draft report sets out AEMO's draft recommendations and reasons and invites stakeholders to make submissions on these recommendations by 20 April 2023.

Under NER 5.2.6A, AEMO must conduct a review (Review) of some or all of the technical requirements of Schedules 5.2, 5.3 and 5.3a at least once every five years to assess the need for amendment. The schedules relate to the access standards for connection of generators, customers and market network services. In accordance with this obligation, AEMO has published this draft report setting out its recommendations for amendments to technical requirements of these schedules, and the reasons for its recommendations.

AEMO invites stakeholders to make written submissions on the technical requirements and recommendations in this draft report. Submissions must be submitted by close of business on 20 April 2023 to email address contact.connections@aemo.com.au.

The next stage of this Review will be AEMO's development of draft NER amendments, which will be informed by feedback received on recommendations set out in this draft report. AEMO will consult with stakeholders on the draft rules, which it will endeavour to finalise for incorporation into the final report under this Review. Further details of expected timeframes and consultation processes are set out in the following subsections.

1.1 Background

Schedules 5.2, 5.3 and 5.3a of the NER detail the technical requirements for the connection of generators, customers and market network services respectively to the national grid, and the capabilities they must deliver to support the secure operation of the power system and use of its networks for the benefit of all users.

These technical requirements are expressed as access standards to be met and maintained for relevant plant that connects to the national grid. These are to be agreed between the connecting party and the network service provider (NSP) within the parameters set out in the schedules, and with AEMO's advice where specified. The agreed access standards for a plant are incorporated into the connection agreement and become the registered 'performance standards' with which the associated registered participant must comply under the NER.

In September 2017, AEMO submitted a rule change request to the Australian Energy Market Commission (AEMC) which, commencing on 5 October 2018,[4] resulted in significant changes to the NEM technical requirements for generators, as well as the requirements in NER 5.3.4A relating to the proposal and acceptance of negotiated access standards. Relevantly, this rule change also resulted in the obligation on AEMO to conduct the Review.

[4] AEMC Generator technical performance standards Rule change, 2018

In October 2022, AEMO published the approach paper that described the matters that AEMO proposed to review. This draft report is the second publication for the Review, which presents initial recommendations on proposed changes to the NER technical standards for connection.

1.2 Rule obligation

NER 5.2.6A(a) stipulates that, at least once in every five-year period[5], AEMO must conduct a review of some or all of the technical requirements set out in:

- Schedule 5.2 – Conditions for connection of Generators and Integrated Resource Providers (IRP)[6]
- Schedule 5.3 – Conditions for connection of Customers
- Schedule 5.3a – Conditions for connection of Market Network Services.

The Review must assess whether these requirements should be amended, having regard to criteria prescribed by the NER (review criteria), being:

- the national electricity objective (NEO)[7];
- the need to achieve and maintain power system security;
- changes in power system conditions; and
- changes in technology and capabilities of facilities and plant.

The NER require that AEMO publish the following documentation in respect of this review, a:

- Draft report setting out its recommendations for any amendments to the technical requirements set out in the above NER schedules and the reasons for those recommendations. AEMO must invite feedback on the draft report and publish submissions received on its website, subject to obligations in respect of confidential information.
- Final report setting out its recommendations for any amendments to the technical requirements set out in the above NER schedules. This final report must have regard to the review criteria and submissions made in response to its draft report.

As soon as practicable following the publication of the final report, AEMO must provide written notification to the AEMC as to whether it will submit a rule change request on the basis of Review outcomes.

In conducting this Review, AEMO must consult with the Reliability Panel and other affected parties.

[5] From October 2018 when the Generator technical performance standards Rule change commenced.

[6] The assessments and recommendations in this draft report have been based on NER requirements including the changes made by the National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021. These will come into full effect on 3 June 2024 (when the IRP registration category is introduced), but Schedule 5.2 changes are being applied from 15 March 2023 to recognise bidirectional units and IRS: https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem.

[7] The National Electricity Objective is: "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: price, quality, safety and reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system."

1.3 Scope of Review

As described above, this Review is assessing the need for amendments to the technical requirements relating to the conditions for the connection of generators and IRPs, customers and market networks services. For the purpose of stakeholder discussions, issues were disaggregated into four groups of standards, being: generation, grid-forming, load, and high-voltage direct current (HVDC).

The Review considers amendments required to the current version of the NER (version 194 at the time of preparing this draft report), as amended to incorporate changes introduced by the National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021 (IESS Rule), as if the rule were in full effect. For example, the IESS Rule introduces the IRP registration category, and the terms “integrated resource system” (IRS), ‘bidirectional unit” (BDU) and “production unit” (which includes both generating units and bi-directional units).

In conducting the Review, AEMO has also been informed by the work undertaken in connection with the processes described in section 1.5.

1.4 High-level objectives and review criteria

High-level objectives of the Review were identified and refined by discussions with internal and external stakeholders. Each recommendation in this draft report seeks to achieve one of more of the following high-level objectives, developed with regard to the review criteria.

- Align with best power system performance:
  - Most access standards are written with automatic access standard (AAS) and minimum access standard (MAS) levels. Plant that meets the AAS must be accepted for connection. It is therefore essential that the technical requirements, especially the AAS, align with achieving an appropriate level of power system performance to meet the network performance requirements and, in turn, the system standards for the benefit of all network users.
- Improve power system resilience:
  - Orient the technical standards towards more resilient performance under abnormal power system conditions, or where system strength may be low. As the NEM generation mix changes, system strength is likely to reduce with the reduction in synchronous generation. This can have adverse consequences for power system stability, especially when the system is under stress during multiple contingency events. The technical standards can support resilient operation of the power system by focusing standards related to tuning of plant controls towards stable operation in low system strength conditions.
- Streamline the connection process:
  - Streamline the technical requirements for generation and IRS, to manage the high volume of connections required for the energy transition without compromising power system security. This includes clarifications to remove ambiguity and thereby improve efficiency and reduce negotiation time; removing unnecessary technology-specific or out-dated wording; and removing or refocusing some low value requirements.
- Support efficient investment and operation:

  - Promote more efficient investment and efficient operation in the NEM, consistent with the NEO. For some technical standards there is a trade-off between capital expenditure or operating expenditure and performance. In some situations, the required performance may be beyond that which is useful or usable, or could be provided more cost-effectively in another way. There are some opportunities to consider where more efficient investment in the NEM can be achieved by tailoring the technical requirements better to power system performance requirements.
- Remove impediments for connection of grid-forming (GFM) inverters:
  - Support the integration of grid-forming inverters in the technical standards by amending or adapting relevant technical requirements to ensure they do not inadvertently hinder the connection of GFM technology and the beneficial capabilities it might provide.
- Broaden application of technical requirements to synchronous condenser connections in addition to generating systems and IRS:
  - Capture in Schedule 5.2 generating systems, IRS and synchronous condensers as appropriate, irrespective of the registration category of the person connecting the plant, providing for more consistent treatment of performance requirements for plant that has analogous characteristics and impacts on the power system.
- Broaden the application of technical requirements to all HVDC system connections:
  - The requirements of Schedule 5.3a should cover all HVDC systems, such as regulated interconnectors and connections of multiple offshore wind generating systems, thereby providing more consistent and better coordinated performance of HVDC systems and improving system security.
- Incorporate impact and capability of HVDC systems into technical requirements:
  - Make the improved capability of modern HVDC systems available to the power system, thereby improving system security by increasing the resilience of HVDC systems at a minimal incremental cost.
- Incorporate impact and capability of large loads into technical requirements:[8]
  - Accommodate the anticipated growth of large converter-based loads (for example, large hydrogen hubs), ensuring they have appropriate standards to support their operation as part of the energy transition.

The table below summarises how the high-level objectives take account of the four review criteria.

Table 5 Regard for review criteria in considering Review recommendations

Objectives	NEO	… power system security	Changes in power system conditions	Changes in technology and capabilities…
Align with best power system performance	Yes (security of system)	Yes	Yes	
Improve power system resilience	Yes (security of system)	Yes		
Streamline the connection process	Yes (price of supply)		Yes	Yes
Reduce the capital cost of connections	Yes (price of supply).		Yes	
Support efficient investment and operation	Yes (price of supply).		Yes	

[8] This objective relates to Schedule 5.3 recommendations which will be set out in the addendum to this draft report.

Objectives	NEO	… power system security	Changes in power system conditions	Changes in technology and capabilities…
Remove impediments for GFM inverters	Yes (security of system)	Yes	Yes	Yes
Broaden application of technical requirements to production units and synchronous condenser connections	Yes (security of system)	Yes	Yes	Yes
Broaden the application of technical requirements to all HVDC system connections	Yes (security of system)	Yes	Yes	Yes
Incorporate impact and capability of HVDC systems into technical requirements	Yes (security of system)	Yes	Yes	Yes
Incorporate impact and capability of large loads into technical requirements[9]	Yes (security of system)	Yes	Yes	Yes

1.5 Relevant initiatives and developments

In undertaking the Review, AEMO has considered interdependencies posed by a number of relevant regulatory and technical initiatives and developments, including open and recently completed rule change processes as well as AEMO reviews and stakeholder collaborations. In reviewing AEMO's recommendations, stakeholders should be aware of these initiatives and developments as summarised in the below table.

Table 6 Interdependencies of the Review with relevant initiatives and developments

Initiatives & Developments	Interdependencies and considerations
AEMC Rule change – Efficient management of system strength[10] (ERC0300)	This Review incorporates amendments to the NER resulting from this 2021 rule change. Revisions to the system strength framework affect NER Schedule 5.2.
AEMC Rule change – Integrating energy storage systems in the NEM[11] (ERC0280)	This Review incorporates amendments to the NER resulting from the IESS Rule, which will be implemented in full on 3 June 2024 but changes to the Schedule 5.2 standards to accommodate bidirectional units will be effective from 15 March 2023.
AEMC Rule change process – Efficient reactive current access standard for inverter-based resources[12] (ERC0272)	The AEMC has recently published its draft determination on this rule change proposal, which is focused on revising the MAS under S5.2.5.5 by specifying the nature of the reactive current response that inverter-based resources (IBR) must provide in response to a fault. This Review focuses on amending the AAS under S5.2.5.5, in a manner that does not conflict with the MAS changes.
AEMC Rule change – Operational Security Mechanism (OSM)[13] (ERC0290)	The final determination on this rule change proposal is currently expected in late July 2023. The AEMC has been considering options that would improve arrangements for maintaining security of the power system. This is to be achieved by establishing an OSM to value, procure and schedule security services in the NEM, in the operational timeframe. AEMO will accredit the facilities to be used for OSM services, and this Review will consider (to the extent currently possible) technical requirements for connection under relevant NER Schedules that may be referenced in OSM guidelines to be developed.

[9] Recommendations to be set out in addendum to this draft report.

[10] See https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

[11] See https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem.

[12] See https://www.aemc.gov.au/rule-changes/efficient-reactive-current-access-standards-inverter-based-resources.

[13] See https://www.aemc.gov.au/rule-changes/operational-security-mechanism.

Initiatives & Developments	Interdependencies and considerations
AEMC Reliability Panel Review – Frequency Operation Standard (FOS) Review 2022[14] (REL0084)	With the FOS review due for completion by April 2023, the Reliability Panel has been investigating revised FOS settings for implementation from October 2023 given the ongoing energy market transformation, as conventional synchronous generation leaves the market and inverter-based technologies enter the NEM. This Review will consider (to the extent currently possible) any change to, among other things, the rate of change of frequency and frequency standards settings for contingency events, both of which may impact technical requirements for connection.
AEMO Scheduled Lite Rule change request[15] (ERC0352[16])	AEMO submitted this rule change request to the AEMC in January 2023, to introduce a voluntary 'light scheduling' mechanism aiming to lower barriers and offer incentives for price responsive, distributed resources to provide visibility and participate in the market scheduling process of the NEM. Although a key focus of the mechanism is to improve visibility and better integrate consumer energy resources (CER) into the market, it will also accommodate a range of resources that currently do not participate in scheduling processes, such as large customer installations. As part of this Review, AEMO will monitor progress of this pending rule change and account for developments that may affect NER Schedule 5.3.
AEMO S5.2.5.10 guideline for Asynchronous Generating Systems[17]	On the basis of stakeholder feedback that there is uncertainty regarding the requirements of clause S5.2.5.10 "Protection to trip for unstable operation" and the requirements to the Power System Stability Guidelines (PSSG), AEMO is seeking to develop and communicate a consistent understanding via a new S5.2.5.10 Guideline and amendment of the PSSG. This Review will consider any relevant amendments to NER S5.2.5.10 arising from that process.
AEMO Voluntary Technical Specification for GFM inverter capability	AEMO is leading a collaborative process with stakeholders to develop a voluntary GFM inverter specification. The specification is intended to accelerate development of GFM technology to suit NEM power system requirements, by providing guidance to original equipment manufacturers (OEMs) and developers on necessary inverter capabilities. The voluntary specification will be used to inform future regulatory change in technical standards, service specifications, and procurement processes. Developments and stakeholder feedback relating to the specification have been considered in this Review in developing technical requirements to support the connection of GFM technology.
AEMO Engineering Framework[18]	AEMO's Engineering Framework aims to define the range of operational, technical requirements to prepare the NEM for future operating conditions including for 100% instantaneous penetration of renewables. It has identified gaps between current and future operating conditions that have implications for technical requirements or standards including those the subject of this Review. Relevant initiatives include a review of treatment of GFM –inverters in the connection process under the current NER technical requirements, and an initiative to develop a voluntary specification.
Connections Reform Initiative (CRI) reforms	Through the CRI, AEMO, the Clean Energy Council (CEC) and NSPs are collaborating to progress a suite of reforms to connections processes. This work seeks to reduce connection time and costs arising from the complexities of the NEM transformation. The reforms include initiatives to: • Streamline the end-to-end connection process • Support information fidelity and quality of data and models provided by Original Equipment Manufacturers (OEMs) • Identify and implement opportunities to streamline the process followed by a proponent proposing to alter an existing generating system • Increase investment certainty for a connection applicant seeking to register their plant to the NEM. Reforms may take effect through amendments to internal procedures, Guidelines and/or the NER. This Review does not take into account process issues, however, where it has or will identify any process issues, there may be potential for these to be addressed by under the CRI.
Renewable Energy Zone (REZ) development	The fast-paced development of REZs, especially in New South Wales (NSW), Victoria and Queensland, may result in amendments to the current connections framework for those networks. Such solutions would, among other things, mitigate the challenges of integrating a high penetration of variable renewable energy within the NEM. For example, the NSW REZ connections process included the development of mandatory access standards, which are intended to allow well-designed generating systems and bi-directional systems to connect to the REZ without negotiation. The consultation feedback received by Energy Corporation of NSW (EnergyCo) from stakeholders provided useful initial input into this Review.

[14] See https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022.

[15] See https://aemo.com.au/initiatives/trials-and-initiatives/scheduled-lite & https://www.aemc.gov.au/rule-changes/scheduled-lite-mechanism.

[16] See https://www.aemc.gov.au/rule-changes/scheduled-lite-mechanism.

[17] See https://aemo.com.au/consultations/current-and-closed-consultations/ner-s52510-guideline-consultation.

[18] See https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

2 Consultation approach

A methodical and thorough issues identification and prioritisation process, informed by comprehensive stakeholder consultation, has established a solid foundation for AEMO's recommended amendments to the relevant NER schedules.

2.1 Draft report publication

This draft report will be published in two parts:

- Part 1, this document, the primary draft report, sets out AEMO's recommendations for amendments to Schedule 5.2 (Conditions for connection of Generators and Integrated Resource Providers) and Schedule 5.3a (Conditions for connection of Market Network Services).
- Part 2, an addendum to the draft report, to be published shortly after the draft report, setting out AEMO's recommendations for amendments to Schedule 5.3 Conditions for connection of Customers.

The reporting has been split because of the additional complexity in developing technical requirements appropriate to address emerging and future issues associated with large loads of a diverse and changing nature, where the current requirements are very limited.

The recommendations and associated discussion for Schedules 5.2 and 5.3a are based on existing technical requirements, where it is generally (although not always) more straightforward to articulate the issues and a range of options for consideration with the benefit of actual experience in applying the requirements. The prioritisation of issues and evaluation of options against the Review objectives has been a significant body of work which AEMO is keen to seek stakeholder feedback on, while finalising its draft reporting on the Schedule 5.3 recommendations. These have taken longer to develop as they require an overarching policy approach to the application of technical requirements that is consistent and takes into account the emerging impacts of large loads on the system. AEMO is also aiming to appropriately balance the costs and benefits to customers with the needs of the system.

2.2 Issues identification and prioritisation

2.2.1 Identification of issues

To identify issues for consideration under this Review, AEMO conducted a scoping exercise taking into account technical requirements of the relevant NER schedules, the review criteria, emerging issues impacting technical requirements, and interdependencies associated with related initiatives. Specifically, issues were identified via feedback from:

- AEMO connections and operations teams and its consultants engaged for the Review, DIgSILENT Pacific.
- Network service providers (NSPs).
- CRI workshop attendees.
- The Central West Orana (CWO) REZ access standards consultation.

- Individual stakeholders to AEMO.

These issues were included in the approach paper which initiated this Review in October 2022, and have been developed, refined and expanded on through further consultation for development of the draft report.

2.2.2 Refinement and prioritisation of issues

AEMO considered a total of 68 issues based through the approach paper and feedback on it (see Appendix A1 for a complete list). Through a series of stakeholder workshops, described in more detail below, 14 of those issues were omitted from further consideration in the Review, as there was broad consensus that they were low priority and would require moderate to high effort to resolve. Low priority issues that are straightforward to resolve were typically not omitted. A further two issues were considered, but ultimately AEMO determined not to recommend an amendment in those cases. Omitted issues are summarised in section 0 of this draft report.

Based on the outcomes of the prioritisation process, follow-up options assessment workshops were held covering 28 of these issues (across all three schedules).

2.3 Stakeholder consultation

AEMO is committed to open engagement with stakeholders and the development of solutions that balance priorities across affected parties as far as practical given the review criteria. The extensive consultation to inform this Review has therefore been critical, given the complexity of issues being considered and the diversity of impacts across multiple groups of affected parties. To this end, AEMO acknowledges the contribution of time and input by a range of stakeholders including representatives from NSPs, connection proponents and market participants, OEMs, and industry associations.

Any stakeholder wishing to discuss or obtain further information on this Review may do so by emailing the AEMO Onboarding & Connections division (contact.connections@aemo.com.au) using the subject line, "AEMO review of technical requirements for connection".

2.3.1 Preliminary consultation

In developing the approach paper, AEMO briefed the Clean Energy Council, Energy Users Association, Australian Energy Council, Energy Networks Association, and the Reliability Panel on the proposed scope. Through this consultation AEMO invited feedback on the scope of the Review, and this has informed the issues considered in developing this draft report.

2.3.2 Technical focus groups

AEMO established the following four technical focus groups with which to collaborate, each focused on the following groups of issues:

- General standards.
- Grid-forming inverter standards.
- Large load standards.
- HVDC standards.

Technical focus groups comprise representatives with technical expertise and direct experience with technical requirements from NSPs, market participants (generators and large loads), developers and OEMs. In developing this draft report, AEMO invited technical focus group members to attend a preliminary round of prioritisation workshops, followed by another round of options assessment workshops on more complex issues. AEMO will continue to consult with these groups in the next stage of the Review.

Prioritisation workshops

To develop the draft report, AEMO ran a prioritisation workshop for each of the four technical focus groups to understand views on the criticality of addressing each identified issue, and obtain feedback to refine or amend issues.

Workshop discussions were used to inform AEMO's determination of issues to pursue through this Review, prioritise those identified issues and identify which of them needed further discussion via options assessment workshops.

Options assessment workshops

AEMO ran a follow-up round of options assessment workshops on issues involving greater complexity or with lower levels of consensus around their impact, interpretation or potential resolution. These workshops explored the issues in more detail, with the objective of seeking validation or refinement of the issues, determining the principles that should underpin any solution; and identifying potential options to address the issues.

The workshop discussions were highly valuable to AEMO, and the perspectives expressed by various stakeholder groups were key to optimising recommendations that appropriately balance the needs of various stakeholder groups and the present and emerging needs of the power system, where possible.

2.3.3 Reliability Panel

NER 5.2.6A(a) requires that, when conducting this Review, AEMO must consult with, among others, the Reliability Panel. Accordingly, AEMO has been engaging with and updating the Reliability Panel on a regular basis. AEMO has also received feedback from the Panel throughout the course of the Review.

2.4 Timeframes

The timeframes for the key activities to conduct this review are set out in the table below.

Table 7 Timeframes for Review

Activity	Timing
Approach Paper released	12 October 2022 (complete)
Draft Report (Part 1) published	3 March 2023 (complete)
Draft Report (Part 2) addendum published	Late March 2023
Information forum	12 April 2023
Draft Report (Part 1) consultation closes	20 April 2023
Draft Report (Part 2) addendum consultation closes	30 business days from publication
Draft Rules consultation commences	May-June 2023 (indicative timing)

Activity	Timing
Final Report released	October 2023
AEMC formally notified of outcomes	November 2023 (indicative timing)

2.5 Next steps

2.5.1 Invitation for written submissions

AEMO invites submissions on this draft report from interested parties. Please provide submissions by 5.00 pm AEST 20 April 2023 to contact.connections@aemo.com.au.

Any inquiries and/or meeting requests should be directed to the same email address.

AEMO intends to publish all submissions on its website. Please identify any part of your submission that is confidential, which you do not wish to be published. Respondents should note that if material identified as confidential cannot be shared and validated with other interested persons, then it may be accorded less weight in AEMO's decision-making process than published material. AEMO prefers that submissions be forwarded in electronic format to be published on the AEMO website.

Prior to the submission deadline, AEMO will hold a public forum on the draft report on 12 April 2023. AEMO will publish the time of the forum closer to that date.

2.5.2 Rules drafting

AEMO will consider feedback submitted on its draft report and, on the basis of this feedback, prepare draft rule changes for further consultation. If needed, AEMO facilitate workshop sessions with technical focus groups to work through more complex drafting. Although not a mandatory part of the Review, seeking feedback on detailed drafting should help to identify any unintended effects or residual uncertainty, and provide an opportunity to form a level of consensus prior to final recommendations.

2.5.3 Final Report

Outcomes of feedback on both the draft report and draft rules proposed by AEMO will inform the final report for the Review, to be published in October 2023, pursuant to NER 5.2.6A(e).

2.5.4 Rule change proposal

As soon as practicable after publishing its final report, AEMO will notify the AEMC as to whether AEMO will request rule changes as a result of this Review. Consultation undertaken through the Review process will also inform a decision on whether AEMO will ask the AEMC to consider any proposed changes under the 'fast track' process (section 96A of the National Electricity Law).

3 Recommendations – Schedule 5.2

AEMO has reviewed the technical requirements of Schedule 5.2 and recommends amendments to achieve a range of improvements to the conditions for connection of generating systems and integrated resource systems, including to align with best power system performance, streamline the connection process and help eliminate unnecessary capital costs for connection.

3.1 NER S5.2.1 – Outline of requirements

3.1.1 Application of Schedule 5.2 based on plant type instead of registration category and extension to synchronous condensers

Ref.	Group	Standard type	Objective(s)
#48	General	Whole of NER S5.2.1	• Broaden application of technical requirements to synchronous condensers

Description of issue

NER Schedule 5.2 sets out the details of additional requirements and conditions that Generators must satisfy as a condition of connecting a generating system to the NEM power system. Following the commencement of the IESS Rule, Schedule 5.2 will also cover IRPs, for connection of an IRS (including bi-directional units).

The obligations in Schedule 5.2 are expressed by reference to the 'normal' participant registration categories for those systems (Generators and IRPs), meaning that similar types of plant owned, operated or controlled by a person in a different registered participant category are not captured. In particular, as outlined in the approach paper, synchronous condensers that are not operated as part of a generating system or IRS are not currently captured by any appropriate technical standards in the NER.

At present, a number of installed synchronous condensers in the NEM are owned, operated and controlled by Network Service Providers (NSPs). While some may be associated with the connection of a particular generating system, these NSP-operated synchronous condensers can be located at separate connection points and operate independently of generation.

In future, it is also likely that some existing generating systems will be converted to synchronous condenser operation[19]. While NER 5.3.9 and the process it describes would apply to the conversion of existing generating systems to synchronous condensers, the plant would not be able to meet some of the requirements under NER Schedule 5.2 post-conversion.

Background – current drafting

The introductory text in NER S5.2.1 and the standards in the rest of Schedule 5.2 are expressed as obligations of Generators and Integrated Resource Providers (by definition registered as such by AEMO), as a condition of their

[19] For example, this is contemplated under the Queensland Energy and Jobs Plan at . https://www.epw.qld.gov.au/__data/assets/pdf_file/0030/32988/queensland-supergrid-infrastructure-blueprint.pdf.

connection of a generating system or IRS. These standards may also apply to embedded generating systems for which the owner, operator or controller is exempt from registration, as indicated in NER 5.3©(c), but this is only partially recognised in NER S5.2.1(b) and has been omitted from the table in NER 5.1.2(d).

NER S5.2.1 reads as follows:

(a) This schedule sets out details of additional requirements and conditions that *Generators* and *Integrated Resource Providers* must satisfy as a condition of *connection* of a *generating system* or *integrated resource system* to the *power system*.

(b) This schedule does not apply to a person, in respect of a *generating system* or *integrated resource system* that is or will be owned, operated or controlled by that person, if:

(1) that person has received an exemption from the requirement to register as a *Generator* or *Integrated Resource Provider* under clause 2.1A.2, or is eligible for an automatic exemption under the *registration information resource and guidelines*, subject to any terms and conditions imposed by *AEMO* as part of that exemption; and

(2) that *generating system* or *integrated resource system* is *connected*, or the person intends to *connect* it; and

(3) that *generating system* or *integrated resource system* is intended for use in a manner the *Network Service Provider* considers is unlikely to cause a material degradation in the quality of *supply* to other *Network U€s*.

(c) This schedule also sets out the requirements and conditions which subject to clause 5.2.5 of the *Rules*, are obligations on *Generators* or *Integrated Resource Providers*:

(1) to co-operate with the relevant *Network Service Provider* on technical matters when making a new *connection*; and

(2) to provide information to the *Network Service Provider* or *AEMO*.

(d) The equipment associated with each *generating system* or *integrated resource system* must be designed to withstand without damage the range of operating conditions which may arise consistent with the *system standards*.

(e) *Generators* and *Integrated Resource Providers* must comply with the *performance standards* and any attached terms or conditions of agreement agreed with the *Network Service Provider* or *AEMO* in accordance with a relevant provision of schedules 5.1a or 5.1.

(f) This schedule does not set out arrangements by which a *Generator* or *Integrated Resource Provider* may enter into an agreement or contract with *AEMO* to:

(1) provide additional services that are necessary to maintain *power system security*; or

(2) provide additional services to facilitate management of the *market*.

(g) This schedule provides for *automatic access standards* and the determination of *negotiated access standards* which once determined, must be recorded together with the *automatic access standards* in a *connection agreement* and registered with *AEMO* as *performance standards*.

The NER definitions of a generating system and an IRS (being one or more of the corresponding *units*) both rely ultimately on the definition of a 'production unit', as 'plant used in the production of electricity and all related equipment essential to its functioning as a single entity'. Although 'electricity' includes reactive power, in the context of this definition and its use in the NER (including classification requirements), electricity production seems intended to indicate *active power* (MW). A synchronous condenser is separately defined and distinguished from a generating unit when used in the NER and, on that basis, is unlikely to fit the definition or criteria relating to the classification of a generating or production unit under the NER.

Discussion and feedback

In prioritisation workshops held by AEMO, participants indicated a high level of support in principle for addressing this issue.

The issue is considered in two parts:

A. Establishing that performance standards for plant covered by NER Schedule 5.2 apply to the participants who are registered (and in some cases exempt where provided for under NER Chapter 5) in respect of that plant, irrespective of their registration category.
B. Defining which NER Schedule 5.2 clauses should apply to standalone synchronous condensers.

For part A, consideration must also be given to the relationship of the connecting party and the NSP expressed in NER Schedule 5.2 clauses, as this distinction becomes irrelevant for situations in which the NSP owns, operates or controls plant covered by this schedule and connected to (part of) its own network. In those cases, it is noted that the NSP has obligations to manage its entire network in accordance with the performance requirements of NER Schedule 5.1.

Options

Part A – Performance standards extended to all participants for covered plant types

The options considered to establish performance standards for plant covered by NER Schedule 5.2 for which the registration categories do not apply were:

1. Do nothing, which would rely on each NSP establishing a suitable level of performance for its own synchronous condensers and for any generation or battery storage systems for which a Generator/Integrated Resource Provider is not separately registered. There would be no requirement for registered performance standards and no consistent performance requirements for these types of plant when owned or operated by an NSP or, potentially, another type of participant operating this plant in future.
2. Establish an obligation on NSPs to register performance standards for their plant covered by NER Schedule 5.2, and to establish a compliance plan for this equipment.
3. Replace all the references to Generators or Integrated Service Providers in NER Schedule 5.2 with another defined term (e.g. connected participant or Registered Participant), to apply the schedule more generally, with appropriate interpretation NER clauses to confirm the meaning of the term in the context of the schedule[20]. Corresponding changes may be required elsewhere in the NER, to the extent the access standard schedules and associated performance standards are referenced elsewhere in Chapter 5 or in other defined terms[21].

The ‘do nothing’ option maintains the status quo. Up to now it has been manageable only because there have been few installations of relevant plant for which Schedule 5.2 has not applied. However, in future there is a high likelihood of many more cases, potentially leading to inconsistent or opaque plant performance that could adversely affect power system security, planning or operation.

[20] Including the application of the schedule to exempt participants where clause 5.3.4A (proposal and negotiation of access standards) extends to those parties under the Chapter 5 connection framework.

[21] A less obvious example is the need to replace the word “Generator’s” in the definition of a ‘generating system’. This is a correction that is probably required in any event, as the definition of a generating system should not be dependent on Generator registration,

Option 2 would address the situation for NSPs, but may not cover future cases. For example, if another party wished to install a synchronous condenser as a standalone device, or as part as an installation that did not include registrable generation, Schedule 5.2 would not apply.

Option 3 is a more comprehensive and 'future-proofed' solution, but involves more extensive drafting and detailed consideration of consequential amendments. It would also require clarification of the application of standards that involve the agreement or approval of the NSP in cases where the NSP itself is the operator of the relevant plant.

Part B – Identification and application of NER S5.2 standards to synchronous condensers

The options considered for identifying and applying appropriate technical requirements to a standalone synchronous condenser are:

1. Do nothing.
2. 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, with a list of exceptions also specified in NER S5.2.1 (see Table 8).
3. Amend each standard in Schedule 5.2 that is relevant to synchronous condensers to specify that it applies to synchronous condensers in addition to generating systems and IRS. This would require amendments to apply all Schedule 5.2 requirements other than those specified in Table 8).

A 'do nothing' option would leave performance standards for standalone synchronous condensers unregulated, and a matter for negotiation in a connection agreement (where a third party operator is involved), or simply managed by the NSP within its broader network performance requirements (NER Schedule 5.1). AEMO may also not have visibility of the performance of significant synchronous condensers for planning or operational purposes. This is therefore not considered a viable option.

Of the other two options, the simpler option in drafting terms would be to amend NER S5.2.1. Specifying clauses that do not apply is likely to be simpler than specifying the ones that do apply, as the former category is shorter. However, AEMO notes that option 3 is more consistent with the manner in which Schedule 5.2 is currently drafted, and it would be clear on the face of each individual clause whether or not the relevant requirement applies to synchronous condensers.

Recommendation

Part A

AEMO's draft recommendation is to move forward with option 3 as a more comprehensive solution.

Part B

At this stage, AEMO recommends option 2 for ease of drafting, and will also consider whether changes to defined terms for relevant connected equipment may assist readability and allow for future standalone technologies to be added to the schedule if it is appropriate for them to be covered by similar access standards. It is recommended that all requirements of Schedule 5.2 would apply to standalone synchronous condensers with the exception of those specified in Table 8. These recommended exceptions have been developed based on the technical operability of synchronous condenser technologies, to ensure that the applicable standards are reasonable having regard to the potential impact on power system operation and ability to comply.

Table 8 Exceptions to application of NER Schedule 5.2

Rule	Application
S5.2.4	**Provision of information.** Provisions related to generating systems 30 MW or more to apply to synchronous condensers 30 MVA or more.
S5.2.5.1	**Reactive power capability** Different requirements apply: • Reactive power capability over the range of voltages from 90% to 110% of normal voltage to be documented. Active power draw when operating at maximum absorption and maximum inject of VARs to be documented. • Effect of ambient temperature on operational range also to be documented. • Active power and reactive power output of the system when the synchronous condenser is not operating, to be documented
S5.2.5.5	**Generating system response to disturbances following contingency events** Apply except: • (e)(3), active power recovery, which does not apply • (m)(1), which applies, other than the phrase on to delivering active power to the network • (m)(2), which does not apply
S5.2.5.7	**Partial Load Rejection** Applies, excluding the proviso about loading level.
S5.2.5.8	**Protection of generating systems from power system disturbances** • (a)(2) does not apply. • (c) does not apply. • (e)(2) does not apply.
S5.2.5.11	**Frequency Control** Does not apply
S5.2.5.13	**Voltage and reactive power control** • Power factor control does not apply • Where a synchronous condenser is only required for reactive current injection during faults (fault current) or inertia services, an exemption from voltage control might be possible • Reference to nameplate rating of 30 MW or more in (d)(4) is taken to be 30 MVA for a synchronous condenser • References to active power settling time do not apply • For clause (c) alternative structure of power system stabiliser or power oscillation damper can be agreed with AEMO and the Network Service provider
S5.2.5.14	**Active power control** Does not apply.
S5.2.5.15	**Minimum system strength** Does not apply.
S5.2.6.1	**Remote Monitoring** • Active power is required to be monitored at the connection point only. • Other active power-related quantities, AGC and turbine-related quantities are not required. • Provisions, other than those listed above, relating to generating units or systems of capacity 30 MW or more, apply to synchronous condensers 30 MVA or more where relevant.
S5.2.4	**Provision of information** Provisions related to generating systems 30 MW or more to apply to synchronous condensers 30 MVA or more.

3.2 NER S5.2.5.1 – Reactive power capability

3.2.1 Voltage range for full reactive power requirement

Ref.	Group	Standard type	Objective(s)
#9	General	AAS	• Alignment of the AAS with best power system operation • Streamline the connection process • Support efficient investment and operation

Description of issue

NER S5.2.5.1 sets the reactive power supply and absorption capability as a function of active power rating. The rule currently specifies the AAS for reactive power capability as a function of the generating system's active power capability ('rated active power') and the requirement is constant over the voltage range 90% to 110% of normal voltage at the connection point.

The injection of reactive power at high voltages is not desirable on the power system as it causes high voltage to increase further and puts unnecessary stress on the generating system plant and units. Likewise, the absorption of reactive power at low voltages is not desirable as it causes low voltage to decrease further.

Adding reactive power capability for injection at high voltages and absorption low voltages can add capital costs to the generating system project and, if a lower access standard were to be negotiated, requires additional time and resource to negotiate.

Discussion and feedback

This issue was ranked as important by participants at the prioritisation workshop. Most participants agreed that reactive power injection at 1.1 pu and reactive power absorption at 0.9 pu were not required, and that there were costs associated with providing these reactive power capabilities. One NSP disagreed with the proposal on the grounds that voltage control is not always at the connection point. AEMO notes that selection of a voltage control location that required the connection point or locations within the generating system to operate at higher than 1.1 pu or lower than 0.9 pu would not be consistent with good engineering practice.

Another participant raised concerns about whether limiting the range of voltages for which reactive power is required to be provided would be consistent with power factor or reactive power control. AEMO's view is that, if this proposal is followed, the reactive power control or power factor control would be required to inject or absorb reactive power within the limits proposed under this clause. This would not prevent a system providing more reactive power if the controls were set up to do so.

Options

The options considered to address identified issues were:

1. Do nothing - not preferred. Prioritisation indicated high support for improving this Rule
2. Modify the AAS to include a voltage-dependent requirement for reactive power
   - Limit the requirement for full reactive power capability to a 10% voltage band around a centre point nominated by the NSP
   - For voltages within the 10% voltage band, require 0.395 x Pmax reactive injection and absorption

- For voltages below the 10% voltage band down to 90%, require 0.395 x Pmax reactive injection
- For voltage from the lower limit of the 10% voltage band to 90%, the requirement for reactive absorption decreases linearly with decrease in voltage from -0.395 x Pmax to +0.395 x Pmax
- For voltages above the 10% voltage band up to 110%, require 0.395 x Pmax reactive absorption
- For voltage above the upper limit of the 10% voltage band to 110%, reactive injection reduces linearly from 0.395 x Pmax to -0.395 x Pmax MVAr

3. Modify the AAS with voltage dependent requirement for reactive power – wider full injection/absorption ranges
   - Limit the requirement for full reactive power capability to a 10% voltage band around a centre point nominated by the NSP
   - For voltages within the 10% voltage band, require 0.395 x Pmax reactive injection and absorption
   - For voltages below the 10% voltage band down to 90%, require 0.395 x Pmax reactive injection
   - For voltage from the lower limit of the 10% voltage band to 90%, the requirement for reactive absorption decreases linearly with decrease in voltage from -0.395 x Pmax to zero
   - For voltages above the 10% voltage band up to 110%, require 0.395 x Pmax reactive absorption
   - For voltage above the upper limit of the 10% voltage band to 110%, reactive injection reduces linearly from 0.395 x Pmax to zero
4. Modify the AAS considering impact of voltage droop settings on potential range for full reactive
   - Five percent change in voltage setpoint would provide less change in voltage.

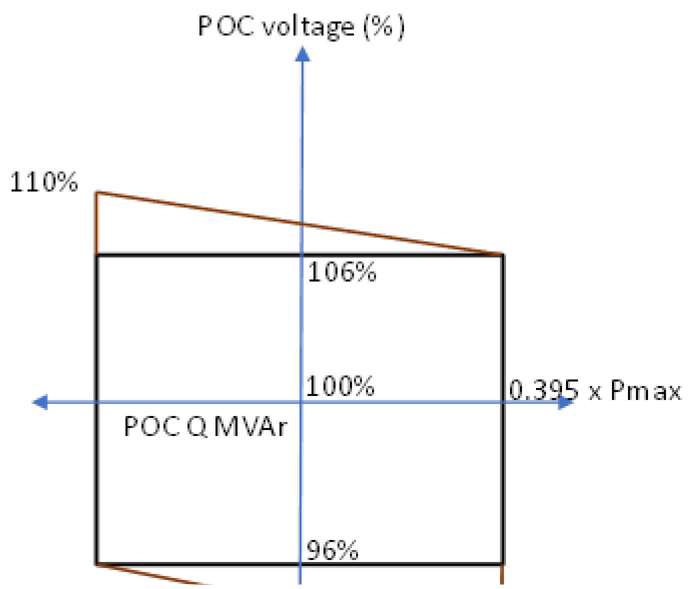

Figure 1 Example for Option 2. In this example, the range is 106% to 0.96% of normal voltage for full reactive power injection and absorption. For values above 106% the required injection reduces until at 110% only full absorption is required. At voltages lower than 96% the amount of absorption required is reduced, until at 90% only full injection is required.

Figure 1 shows an example of application of option 2, where the full range of injection and absorption centres around 101% of normal voltage.

Option 4 is as per Option 2 but considers the impact of voltage droop on the range of voltages that could occur. With voltage droop, the range of voltages for +/-5% voltage setpoint (as required for the AAS of NER S5.2.5.13) would be less than 10%. However, this option is oriented towards voltage control with droop, which may not be relevant to the control modes agreed in NER S5.2.5.13. In addition, even if voltage droop is used, droop settings may change over the life of the plant, which would result in a mismatch with NER S5.2.5.1.

Option 3 is the same as Option 2 except that the reactive absorption range is wider at voltages down to 90% of normal voltage and likewise the injection range is wider at voltages up to 110%. AEMO operations prefers this alternative to Option 2, because it allows more flexibility for operating at lower voltages, without the plant countering the low voltages.

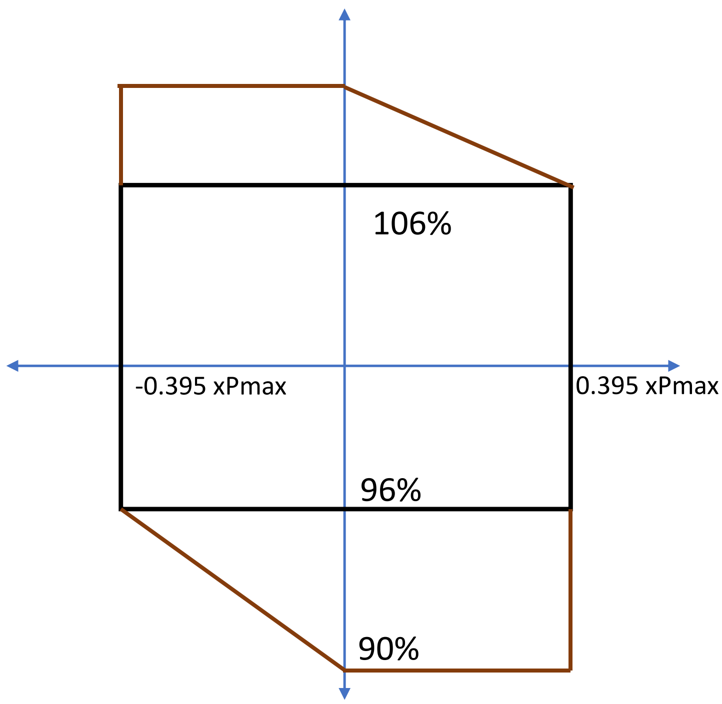

Figure 2 Example for Option 3, also using 106%-96% as the full range component.

Recommendation

AEMO recommends Option 3.

3.2.2 Treatment of reactive power capability considering temperature derating

Ref.	Group	Standard type	Objective(s)
#11	General	NAS	• Streamline the connection process

Transgrid's response to the approach paper suggested that AEMO consider the documentation of capability derating with temperature in the GPS, under general requirements.

During the discussions on NER S5.2.5.1 participants raised further issues regarding inconsistent treatment of temperature derating by various NSPs and AEMO during connection negotiations.

At present, NER S5.2.5.1 is silent on temperature derating, although it is common practice to document temperature derating. Inverters generally derate proportional to temperature and have a range of operating conditions, although some inverters have water cooling or air conditioning that allows full output over a range of temperatures. Most production units have lower and upper limits on operation, although the lower limits are seldom an issue for operation in Australia.

The reactive power in NER S5.2.5.1 is specified as a function of the rated active power[22], so if apparent power is derated with temperature this raises the question of what active power should be recorded under S5.2.5.1(g) to define the reactive power requirements as a function of temperature.

Rated active power is defined for a generating system or IRS as the maximum amount of active power that in-service generating units can deliver at their nameplate rating, where nameplate rating is:

> The maximum continuous output or consumption in MW of an item of equipment as specified by the manufacturer, or as subsequently modified.

The manufacturer may or may not specify the maximum continuous output as a function of temperature.

There is a range of possible interpretations:

1. Qmax (T) = 0.395 x Pmax(T) for all operating temperatures, T.
2. Qmax (T) = 0.395 x Pmax (Tnm) for all operating temperatures, where Pmax is a function of T, and Tnm is the temperature at which the nameplate rating is determined.
3. Qmax = 0.395 x Pmax(Tmax), Pmax = P(Tmax) for all operating temperatures.

Clearly these different interpretations have different implications for capital expenditure on the plant.

The most commonly applied interpretation historically has been number 1, where the derating of Pmax and Q max has been applied according to the apparent power derating of the plant. This is generally consistent with the equipment derating behaviour, and relates Pmax to Qmax for the same environmental condition. However, AEMO notes that the term rated active power references the term nameplate rating, which may not be consistent with this interpretation.

Interpretation 2 biases the production of reactive power over active power for all temperatures at which the plant is derated (usually higher temperatures), requiring the plant to limit its active power to provide the same amount of reactive power when the plant is derated. Effectively production of energy is restricted to provide reactive power to support the network at higher temperatures. The incremental cost of energy is very low, so effectively this

[22] And, for an IRS, rated maximum demand.

interpretation deprives customers of very low cost energy for the same capital cost for high temperature conditions. The price of electricity is likely to increase in high temperature conditions, when demand is typically higher. On the other hand, the amount of reactive support provided to the network is maintained regardless of temperature. It is difficult to be definitive about the net benefit or disbenefit to customers and the power system under this interpretation, because the answer may be to some extent site specific. On balance, it seems that this interpretation would more likely cause a disbenefit to customers (i.e. not consistent with the NEO) in most cases, because it increases the capital cost to supply demand at high temperatures when demand is most likely to be at high levels.

Interpretation number 3 is not consistent with efficient investment in the NEM (and therefore not aligned with the NEO), as it would require investment in capacity that will not be useable for most of the plant's life for the sake of achieving a constant maximum active power capability.

Discussion and feedback

This issue in its original form raised by Transgrid was not considered a high priority at the prioritisation workshop. However, it was raised by participants later in workshops dealing with S5.2.5.1 issues, where the issue was more fully articulated and discussed.

Options

The options considered to address this issue were:

1. Do nothing
2. Clarify that for the purpose of this NER S5.2.51, the rated active power or rated maximum demand must take account of the temperature dependency of the rating, and that the required Qmax and Qmin are functions of Pmax as derated. That is, Qmax (T) = 0.395 Pmax (T), and Qmin (T) = -0.395 Pmax(T) for operating temperature T at the connection point, for reactive power absorption.
3. Require the performance standards to document:
   - Active power derating of production units as a function of temperature, if any
   - Reactive power derating as a function of temperature of production units and any other reactive power facility, if any.
   - Maximum operating temperature and minimum operating temperature of the generating system or IRS
   - Maximum operating temperature for which the plant is not derated.
   - Reactive power performance requirement as a function of active power at the connection point at the maximum temperature for which the plant is not derated,
   - Reactive power performance requirement as a function of active power at the connection point at the maximum operating temperature, where different.
   - Reactive power performance requirement at the connection point as a function of temperature.

Since there seems to be inconsistency in the way the rule is currently interpreted, AEMO sees some value in progressing a rule change for this issue. The interpretation that appears to be most consistent with the NEO is interpretation 1, described as option 2 above. To give effect to this for compliance purposes the temperature dependency of Pmax and Qmax would also need to be described in the rules.

Recommendation

AEMO recommends Option 2 and 3.

3.2.3 Compensation of reactive power when units are offline

Ref.	Group	Standard type	Objective(s)
#12	General	General requirement	• Streamline the connection process

Description

NER S5.2.5.1 states that:

A *performance standard* for consumption of energy by a *generating system* or IRS in respect of *auxiliary load* when not supplying or absorbing *reactive power* under an *ancillary services agreement* is to be established under clause S5.3.5 as if the *Generator* or *Integrated Resource Provider* were a *Market Customer*.

auxiliary load

Electricity consumption used for the operation of a *production unit* but excluding electricity consumption used to create the source of energy converted by the *production unit* to produce electrical power.

NER S5.3.5 provides for power factor requirements for loads as a function of voltage e.g. 0.95 lagging to unity for 50 -250 kV, 0.96 lagging to unity for 250-400 kV etc. Note that the reference to lagging, is in reference to a load, and represents inductive (absorbing) power factor.

The MAS of NER S5.3.5 permits a lower lagging or leading power factor where the NSP is advised by AEMO that this will not detrimentally affect power system security or reduce intra-regional or inter-regional power transfer capability.

The general requirements allow for a commercial agreement to cover the actions where a load is unable to meet their performance standard over a critical loading period nominated by the NSP.

The general requirements also provide that a registered participant who installs shunt capacitors for power factor requirements must comply with the NSP's reasonable requirements to ensure the design does not severely attenuate audio frequency signals used for load control or operations or adversely impact harmonic voltage at the connection point.

The intent of this standard is to manage the impact of the generating system (or IRS) on power system voltage at the connection point, when the system's production units are out of service, but other parts of the system are in service.

When a generating system's units are out of service, but other parts of the system are in service, there is typically some net load on the system. For some generating systems there may be insignificant auxiliary load compared with the capacity of the generating system. There may also be some net capacitance, which arises from unloaded cables and lines, and from capacitors used for harmonic filters or reactive power contribution. Other generation types such as thermal synchronous machines may have substantial inductive auxiliary load.

For generating systems that have negligible auxiliary load the power factor may be very low. The impact on the power system will typically be to increase the voltages, but the impact may be small or large depending on the connection and the amount of reactive power injected.

For an IRS, the system may comprise bi-directional production units, different types of production units (e.g. battery energy storage and wind turbines), or production units and load. Considering these possibilities, it is difficult to generalise about the relative size of active and reactive power contribution when the production units are not in service, or about the voltage impact on the power system.

There is a cost associated with correcting the power factor when production units are out of service. Choices are to:

- Disconnect the generating system fully from the power system, which means regular operation of circuit breakers (wear and tear costs), energisation of transformers (which may have power quality implications).
- Operate the production units, while not producing or consuming active power, in a mode that can compensate for the reactive power injection or absorption of the system. For distributed generation and storage systems like solar, wind and battery energy storage systems it is possible to operate a number of units to provide or absorb reactive power when most units are not in service. This comes at an ongoing operational cost, considering losses, and may impose capital costs for addition of this functionality. Operation of synchronous units as synchronous condensers may be possible, but with additional capital as well as ongoing operational costs including losses.

Whether there is net benefit to the power system in compensating the reactive power will depend on the:

- size of impact on voltages, and whether the reactive power from the generating system or IRS is helping or hindering voltages in the network
- cost of providing this corrective response.

Some NSPs require some production units to be kept in service to provide dynamic reactive power capability in voltage control. The access standards do not specifically address such a requirement, but also does not preclude it.

Discussion and feedback

In the prioritisation workshops, participants ranked this issue as of moderate importance. An options assessment workshop was also held on this issue.

As written, NER S5.3.5 requires AEMO to provide advice about the impact on power system security, and inter-regional and intra-regional network limits, for the NSP to permit a performance standard below AAS level. Generating systems or IRS that have a net inductive power impact at the connection point when the production units are out of service have a better chance of meeting the AAS of NER S5.3.5 than those systems that have a net capacitive inductive impact when the production units are out of service, as the power factor ranges allowed in NER S5.3.5 are for various reactive inductive power factors to unity.

In recent times NSPs have expressed concerns about gradually increasing network voltages.

Some participants commented on the additional compliance and testing burden associated with providing reactive power from production units to compensate the reactive injection of the system. This was particularly mentioned in relation to voltage control, but could also apply to other operating modes. If only a small proportion of the system's units are required to compensate the system's reactive power when the production units are otherwise out of service, it would be reasonable to limit the testing and compliance burden commensurate with the low impact on the power system. If on the other hand, a large synchronous generating unit or system was operating as a synchronous condenser, or otherwise if a significant proportion of the total production unit capacity was involved in providing dynamic reactive power, then more detailed compliance and testing requirements would be appropriate.

One participant commented that the active power and reactive power recorded in the performance standards should be treated as steady state values. Transient reactive power, for instance on energisation of transformers or cables may be higher. AEMO agrees that the Rule intends that steady state values are specified, rather than transient loads.

Workshop participants cautioned against any additional requirements in the technical standards that would increase the cost of connection.

Some workshop participants considered that requiring the generating system to compensate its reactive power at the connection point was reasonable. However, considering that reactive power from passive elements is a function of network voltage, it is reasonable to allow a range of reactive power. The present NER S5.3.5 has that already in the AAS, although only for an inductive range. Voltage control is one way of providing compensation of reactive power. A range of reactive power at the connection point would be required to achieve voltage control. AEMO notes that the rule as currently drafted considers supplying or absorbing reactive power under an ancillary service agreement (which would typically be for voltage control services), as an alternative.

Options

These options all consider the reactive power injection or absorption from the generating system or IRS where the production units are not in service.

1. Do nothing
2. Do not require reactive power at the connection point to be restricted where the impact on voltages is less than a voltage threshold, otherwise leave is unchanged.
3. If the voltage impact at the connection point is less than a voltage threshold, permit a range of reactive power outputs in steady state consistent with the power factors specified in the AAS of NER S5.3.5, considering the maximum steady state active power that can be drawn (auxiliary load and losses) when the production units are not in service. Otherwise, restrict the range of reactive power at the connection point to that which would have impact less than or equal to the voltage threshold.
4. If the voltage impact at the connection point is less than a voltage threshold, permit a range of reactive power outputs in steady state that includes both inductive and capacitive range consistent with the power factors specified in the AAS of NER S5.3.5, considering the maximum steady state active power that can be drawn (auxiliary load and losses) when the production units are not in service. Otherwise, restrict the range of reactive power at the connection point to that which would have impact less than or equal to the voltage threshold.
5. Where the Generator or IRP and the NSP agree that maintaining the steady state reactive power within the required range is by means of operating a subset of generating units in voltage control, reactive power control or power factor control, treat this is a secondary operation mode (i.e. reduced compliance assessment). See Section 0 of this report for an explanation of the secondary operating mode concept.
6. Require the documentation of the maximum active power consumption by a generating system or IRS in respect of auxiliary load and the range of permitted reactive power at the connection point, where these represent steady state values.

Option 1 “Do nothing” As written, the rule tends to drive more operational costs for Generators and IRPs than would be consistent with the NEO, because it always requires a generator or IRS to limit the plant’s reactive power output or consumption at the connection point regardless of whether there is a material impact.

Option 2 has a carve out on the requirement to limit reactive power in cases where the impact of the IRS or generating system when the units are offline is less than a threshold value. A suitable threshold would likely exempt small generating systems connected to strong parts of the network from this requirement, which would assist in a small way to streamline connection.

Option 3 is similar to the current requirement, but specifies a narrower range if the voltage impact is greater than the voltage threshold. It also clarifies that the active power and reactive power ranges are steady state values

Option 4 is similar to Option 3, except only permitting an inductive range consistent with the NER S5.3.5. This option compared with Option 3 is more likely to cause wind farms and solar farms to either disconnect at no-wind or no-irradiance conditions or provide control of reactive power by utilising units.

Option 5 could be used in conjunction with Option 2, 3, or 4 to reduce the compliance burden for assessment of voltage, power factor or reactive power control for small numbers of units. The lower compliance assessment requirement would be consistent with there being low risk of adverse impact on the power system from controls from the operation of the units because only the requirement is for a small reactive power range.

Option 6 - Apart from specification of the values as steady state, Option 6 is similar to NER S5.3.5, except that it specifies active and reactive power whereas the rule refers to power factor.

Recommendation

AEMO recommends Option 2, 5, and 6.

3.3 NER S5.2.5.1, S5.2.5.3, S5.2.5.5, S5.2.5.7, S5.2.5.8

3.3.1 Simplifying standards for small connections

Ref.	Group	Standard type	Objective(s)
#49	General	AAS & MAS	• Streamline the connection process

Description

AEMO identified in the approach paper that there may be opportunities to streamline connections of small generating systems and IRS in some cases.

Smaller plants have individually less impact on the power system than large ones, but the impact needs to be considered in the context of its connection location. In addition, there can be a cumulative effect, depending on:

- The number and size of plants connected in a local area, with similar (undesirable) response.
- Whether the disturbance is global or local in nature.
- The nature of the response, and how it affects other plants.

For example, if a small plant connected to the distribution system trips for a voltage disturbance, it is unlikely to cause a power system security issue. If the disturbance were to cause hundreds of megawatts of plant to trip, the cumulative impact could result in a power system security issue, if not managed, or a network constraint, if managed. If the response is such that the plant trips frequently, it may cause a power quality issue for the distribution network. Depending on the size of the plant, relative to the system impedance of its connection, when it trips it might cause a large voltage disturbance on the local network, which might (depending on state-based regulations) be outside of the permitted voltage range on the distribution network.

The technical standards are written with automatic and minimum standards, to take account of the differences from one connection to the next, to promote more efficient investment. However, differences relating to the size or impact of the plant on its connection point and the wider power system cannot always be accounted for. Some standards such as S5.2.5.5 MAS (fault ride through impacting less than 100 MW) and S5.2.5.13 MAS (plants less than 30 MW) have relaxations of requirements based on size. The approach paper proposed that AEMO should take a broader look at the clauses in Schedule 5.2 to examine whether further opportunities exist to further reduce any requirements that may be unnecessarily onerous for smaller plant.

Discussion and feedback

Participants at the prioritisation workshop ranked this issue medium importance. The options assessment workshop took an exploratory approach, inviting participants to comment on standards in S5.2.5. There was general agreement that a risk-based approach was appropriate.

Options

AEMO and workshop participants identified the following rules for possible relaxation:

Table 9 Potential amendments identified for relaxation

NER / access standard level	Description of potential amendment
S5.2.5.1 AAS	Set the reactive power required for injection and absorption to be the lower of 0.395 x Pmax and the reactive power that would give rise to a [5%] voltage change, for generation connected to a distribution network. 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.
S5.2.5.3 AAS	S5.2.5.3 – Continuous uninterrupted operation (CUO) requirements at high frequency only might be relaxed, for small plant [30 MW]. CUO requirements at low frequency and for high RoCoF cannot be relaxed as tripping in those circumstances would exacerbate a global disturbance. This is one case where a cumulative impact might result in an underfrequency event, if enough small generators were to trip. The MAS already exempts plant less than 30 MW from remaining in CUO for the upper bound of the operational frequency tolerance band to the upper bound of the extreme frequency excursion tolerance limits (including an "island" condition) for at least the transient frequency time.
S5.2.5.5 AAS, MAS	For plant less than [30 MW] connected to the distribution network at MV or LV level, the technical requirements could omit the reactive current injection requirements but retain the existing contingency and fault ride through requirements. Such plant will, by virtue of its size and connection level, contribute little to the voltage stability of the power system during faults. The plant would still need to inject sufficient reactive current to ensure it remained in CUO as required, but the rule not require it to assess the level of reactive current it injects nor any of the associated requirements on the speed or shape of reactive current response. Note that the AEMC has proposed a lower MAS for reactive current injection in its draft determination on the Efficient Reactive Current Access Standards for Inverter-based Resources rule[23]. The MAS would permit a lower reactive current injection to be negotiated, so this is not a question of an impediment (for IBR), but about a reduced negotiation process that requires performance commensurate with the impact of the plant on the power system.

[23] At https://www.aemc.gov.au/rule-changes/efficient-reactive-current-access-standards-inverter-based-resources.

NER / access standard level	Description of potential amendment
S5.2.5.7 AAS, MAS	Tripping of small generation for a load rejection would generally relieve the overfrequency event associated with the event, unless more generation than load tripped. As the automatic access standard refers to 30% load rejection, tripping more generation than load is unlikely to occur. It is highly unlikely that any modern generating system would be unable to remain in CUO for a 5% load rejection. Considering this, it would be very low risk to exempt small generation from assessment under S5.2.5.7. Since load rejection of the scale contemplated in the rule is rare, tripping of small generation in such events is unlikely to be a power quality issue.
S5.2.5.8 MAS	Emergency over-frequency generation runback – It has been proposed to align requirements with the S5.2.5.3 proposed AAS change and existing MAS and make the exemption consistent at 30 MW. See general requirements section 3.8.1 for more information.

For each of these possible relaxations there is also a “do nothing” option.

To reduce the negotiation process time for small plant, and the resource required, it is also proposed to exclude from AEMO advisory matters and generation or load connection to the LV or MV network of a distribution less than [30 MW].

Recommendation

AEMO recommends the following amendments:

- S5.2.5.1 AAS: Set the reactive power required for injection and absorption to be the lower of 0.395 x Pmax and the reactive power that would give rise to a [5%] voltage change, for generation connected to a distribution network.
- S5.2.5.3 AAS: Do nothing
- S5.2.5.5 AAS, MAS: Exempt synchronous and asynchronous generating systems and IRS less than [30] MW connected at MV or LV level, from assessments related to reactive current injection
- S5.2.5.7 AAS, MAS: Exempt generating systems and IRS, in respect of generating units, of combined nameplate rating less than 30 MW, from this clause in both automatic and minimum access standards
- S5.2.5.8 MAS: See proposal under General S5.2 section 3.8.1.

AEMO seeks specific feedback from stakeholders on these proposals, and particularly the thresholds in square brackets.

In addition, AEMO proposes to exclude from AEMO advisory matters and generation or load connection to the LV or MV network of a distribution less than [30 MW].

3.4 NER S5.2.5.2 – Quality of electricity generated

3.4.1 Reference to plant standard

Ref.	Group	Standard type	Objective(s)
#13	General	General	• Streamline the connection process

Description

AS 1359.101 (1997) and IEC 60034-1 are referenced as plant standards for synchronous generating units for harmonic voltages in NER S5.2.5.2. The former Australian Standard was superseded by AS1359.0-1998 (which has subsequently been withdrawn) and AS 60034.1-2009. IEC 60034-1 published by the International Electrotechnical Commission is the equivalent standard to AS 60034.1, but references the current version from 2022.

The IEC 60034-1 includes reference to total harmonic distortion measurement for synchronous machines.

Discussion and feedback

This issue was not rated highly in the prioritisation workshop. However, it also did not receive opposition. The change would simply remove something that has become irrelevant.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Remove the reference to the superseded standard.

Since the current AS is an older version of the IEC standard that is already listed in the clause, the simplest change would be to omit the superseded standard and retain the existing reference to IEC 60034-1.

Recommendation

AEMO recommends Option 2.

3.5 NER S5.2.5.4 – Generating system response to voltage disturbances

3.5.1 Overvoltage requirements for medium voltage and lower connections

Ref.	Group	Standard type	Objective(s)
#19	General	AAS & MAS	• Streamline the connection process

Description

In the technical standards review that formed the basis of the 2018 rule change (ERC0222), the overvoltage requirements were increased, following the 2016 South Australian black system event. In that event, the transmission network experienced overvoltages in some places in that exceeded the system standards (measured >120% for several seconds). Studies for the special protection scheme after this event suggested generating systems could disconnect from the power system, exacerbating the disturbance.

The duration for which generating systems were required to remain in continuous uninterrupted operation (CUO) for overvoltages was also increased as part of those 2018 changes. The 2018 Rule change proposal suggested increasing the system standard to up to 115% for 1200 s (20 minutes) with reference to a CIGRE WG 33.10 publication on Temporary Overvoltage characteristics of Extra High Voltage Equipment. The Rule change also referred to the ENTSO-E requirement for plant connected to the 400 kV system to ride through overvoltages of

115% for 20-60 minutes. However, the ENTSO-E requirements also have lower requirements for plants connected at lower voltages, for example, 105% - 110% for 20-60 minutes for connections at 110kV to 300 kV level.

The rationale for the 2018 Rule change focussed on high voltage (HV) transmission level connections, but the current standard applies to connections at any voltage. Most plant designed to operate at 33kV is rated for a maximum of 36 kV continuously. The ability of plant to sustain 20 minutes duration at 115% relies on the operation of transformer tap changes to bring medium voltage (MV) levels down to within the normal range for operation. However, plant connected at MV levels and lower is often directly connected, not through a tap changing transformer. It is not consistent with efficient investment in the NEM to require capital expenditure on transformers for on MV or LV connected plant, for a performance requirement that derives from HV system issues. The automatic access standard requirements for 115% to 120% for 20 seconds, 120% to 125% for 2.0 seconds, and 125% to 130% for 0.2 seconds may also present difficulties for directly-connected plant.

This issue is present in the automatic access standard. The provisions for negotiation in NER S5.2.5.4(c) require:

> In negotiating a *negotiated access standard*, a *generating system* or *integrated resource system* and each of its operating *production units* must be capable of *continuous uninterrupted operation* for the range of voltages specified in the *automatic access standard*, except where *AEMO* and the *Network Service Provider* agree that the total reduction of generation in the power system as a result of any voltage excursion within levels specified by the *automatic access standard* would not exceed 100 MW, or a greater limit based on what *AEMO* and the *Network Service Provider* both consider to be reasonable in the circumstances.

This issue was first considered in discussions related to the Central West Orana Renewable Energy Zone (CWO REZ) access standards, which were set at a single mandatory level. In the CWO REZ there may be many plants connected at MV level. Likewise, the situation can also arise for situations in which the HV/MV transformer is a dedicated network asset (DNA) shared by multiple plants[24]. In this situation, as in the REZ, connections greater than 100 MW are likely. The rule has some flexibility above 100 MW, at the discretion of the NSP and AEMO, although not for the CWO REZ, where mandatory standards apply.

Discussion and feedback

Participants at the prioritisation workshop ranked this issue as medium importance. A follow up options analysis workshop was undertaken for this issue. Participants were generally in favour of addressing the issue and comments were generally supportive of the concepts.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Amend the automatic access standard to make the point of application of overvoltages the nearest HV transmission location, for MV connections not through a transformer with onload tap changer.

[24] See the "Connection to dedicated connection assets" Rule change. At https://www.aemc.gov.au/rule-changes/connection-dedicated-connection-assets.

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.
4. Move the point of application (as in Option 2), but only for small plant.

As there is some flexibility in the rules, this issue is not so much an impediment to connection, as an area in which the connection process could be streamlined, by reducing the need for negotiation in some instances where the risk to power system is minimal. Operation at 115% of normal voltage for 20 minutes and 115% - 120% for 20 s are well outside the system standards (approximately 1.6 s for 110 – 117%, from S5.1a.4), so this is not a question of power system security. The overvoltages defined in S5.2.5.4 are targeting resilience and, as previously noted, justified on the basis of HV overvoltages.

Considering the reasons for the overvoltage requirements AEMO considers that there is some scope to vary the requirements for MV connections, without material impact on the power system resilience.

Option 2 is similar to the amendment adopted for the CWO REZ. The nearest HV transmission point would usually be at the HV terminals of the nearest bulk supply transformer. If the plant were connected a long way from the transmission HV system (and therefore, through a large impedance), then the requirement at the connection point would be lower. However, one would not connect a large plant through a large impedance to the HV transmission, because of considerations of power transfer capability, losses and voltage drop.

Option 2 relaxes the automatic access standard for MV and LV connected plant, in a way that is unlikely to affect the performance of the power system. The main disadvantage would be that it could add complexity to compliance assessment, if measurement of overvoltages is only at the connection point. However, a power system model can be used to identify the voltage at the nearest transmission point, for a measured voltage at the connection point, should compliance need to be investigated. It would apply to small distribution connections as well as connections through DNAs, which could be large.

Option two combines two conditions:

- MV connection, because the overvoltage requirements were established to manage potential HV conditions.
- Not through a tap changing transformer, because an MV connection through a tap changing transformer would have more capability to meet the current AAS requirements.

Option 3 reduces a restriction on negotiation below AAS to a level consistent with FCAS requirements.

Option 4 makes the relaxation only for small plant. Considering NER S5.2.5.4(c), this option would add little overall value.

Recommendation

AEMO recommends NER amendments to give effect to Options 2 and 3.

3.5.2 Requirements for overvoltages above 130%

Ref.	Group	Standard type	Objective(s)
#18	General	AAS	• Streamline the connection process

Description

The present formulation of the highest overvoltage requirement in NER S5.2.5.4 is:

(a) The *automatic access standard* is a *generating system* and each of its *generating units* must be capable of *continuous uninterrupted operation* where a *power system* disturbance causes the *voltage* at the *connection point* to vary within the following ranges:

(1) over 130% of *normal voltage* for a period of at least 0.02 seconds after T(ov);

…

The main problem with this rule is that the drafting leaves the upper voltage for continuous uninterrupted operation open-ended, but defines a duration for which it must remain in operation. Technically by this definition, a plant that trips for 130% in 21 ms is compliant, but a plant that trips for 250% overvoltage in 19 ms is non-compliant.

Note that the voltages in this clause are specifically described, but are generally considered to be power frequency rms values, consistent with the system standards. However, peak voltages of the order of 130% would typically be caused by either switching overvoltage or lightning flashes, as illustrated in Figure 3 below.

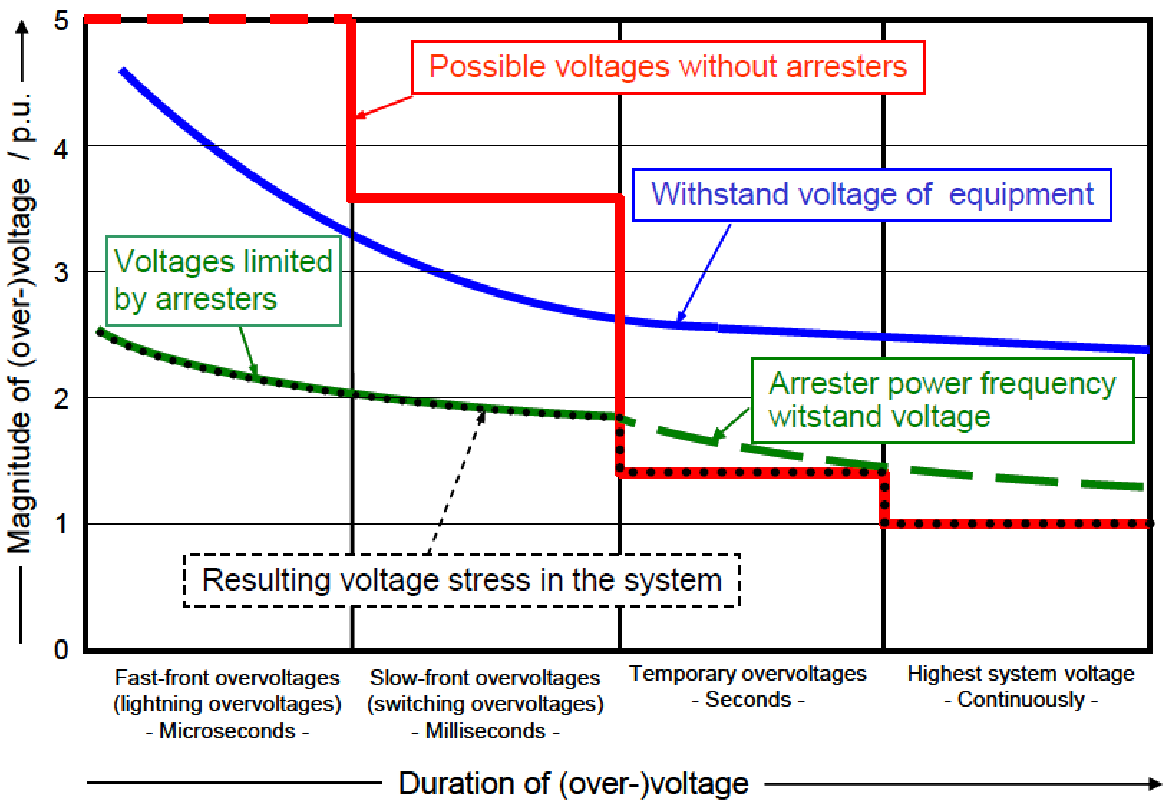

Figure 3 Over-voltage insulation coordination and impact of surge arresters[25] Voltages in this figure represent peak rather than rms values.

[25] Volker Hinrichsen "Metal Oxide Surge Arresters in High Voltage Applications. Fundamentals". 3rd ed 2011

In the context of these phenomena, the voltage shape is not sinusoidal. The aspects of relevance are the peak voltage, and the energy, because in timeframes of less than 20 ms protection is by means of surge arresters, which have finite capability to absorb energy. Typically, the slow-front overvoltages from switching surges have higher energy, and are therefore likely to be the main consideration for insulation coordination and surge arrester selection. Good engineering practice for insulation coordination employs standardised assumptions about switching and lightning overvoltage waveforms and a probabilistic approach. In reality, waveforms may differ from the standardised assumptions. It is therefore impractical to expect generating systems or IRS to remain in continuous uninterrupted operation for overvoltages without an upper bound, for durations up to 20 ms.

In terms of the production units, synchronous machines can practically do very little to respond to these types of disturbance. IBR equipment may be able to block the operation of insulated-gate bipolar transistors (IGBTs). Considering the timeframes involved it would be reasonable to permit blocking of overvoltages for less than 20 ms to protect plant from damage due to overvoltages. Practically, the IBR plant will protect itself by reference to peak terminal voltages, not the connection point rms voltage, and it will in any case be difficult to measure the voltage magnitude of a transient overvoltage in that timeframe.

Discussion and feedback

The prioritisation workshop participants ranked this issue of medium importance. Comments suggested that the issue was not well understood, and that some participants took the present drafting of “over 130%” to mean “at least”. The issue was further discussed at an options assessment workshop, considering the options outlined below.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Change general requirement on negotiation to remove size limit.
3. Change to “at least 130%”.
4. Define an upper–voltage limit - e.g. 140%.
5. Substitute AAS sub-clause for a requirement to design for switching surges “slow front overvoltages” defined in IEC standard IEC 60071.1, 2019, (wave front 250 µs and a halving time of 2500 µs).
6. Specifically allow short-term (<20 ms) blocking to protect units.
7. Options 5 + 6.
8. Option 2 + 4 + 6.

Option 1 is not preferred as it would not address the issues.

Option 2 does not address the issue of the current AAS for this subclause being impractical as drafted, but could simplify the negotiation process.

Option 3, 4 and 5 all address the issue to some extent. Option 4 does not consider the impact of the surge waveshape and duration – a 20 ms surge could be extremely arduous. Option 5 addresses it most directly by recognising that overvoltages at that level and duration are not power frequency voltages.

Workshop participants overwhelmingly preferred the simpler solution of Option 3, which would allow the generating system or IRS to trip.

Further internal discussions with AEMO operations raised some other issues. These include:

- In general, it is desirable for operation of the power system for plant not to trip for switching conditions or contingency events
- There have been instances in the past in which a plant that has been tripping for overvoltages above 130% at its connection point was able to change its protection so as not to trip.

This raises the issue that if a plant is regularly exposed to overvoltages of 130% or more, the overvoltages are likely to be detrimental to its insulation and to the life expectancy of its surge arresters. None of the options considered above address the issue of why the generating system or IRS is being exposed to the overvoltages. Arguably if a plant is being exposed to very high overvoltages, as a result of the design of some network element, the NSP should have responsibility for mitigating those overvoltages, rather than exposing the generator to them. However, the system standards are silent on overvoltages of more than 130% and less than 0.02 seconds, so there is currently no obligation on an NSP to do anything. Consideration should be given to whether the system standards should limit the maximum allowable overvoltage for switching surges, and whether this would reflect a peak or RMS voltage. The outcomes of such a discussion might affect the formulation of an option under this rule.

On the other hand, a generating system or IRS should not trip because of an overvoltage that it has caused. In that circumstance, the obligation and associated compliance risk should lie with the generator as it has the capacity to manage that risk by better tuning of its control systems.

In some cases, the overvoltage might be attributable to multiple plants, with or without contribution of network elements. This becomes quite complex to assess, and would require investigation, and could require coordination of controls among various parties and even changes to network elements (e.g. point on wave switching for network elements).

AEMO considers that there may be need for further discussion with industry on this issue, as to what the most appropriate approach is, and where in the rules the issue should be addressed.

Recommendation

AEMO recommends that risk to generators of this clause be bounded. Given the complexities of the issue, AEMO is seeking input from its stakeholders into the most appropriate resolution, which may be one of the identified options or an alternative. AEMO anticipates working through proposed solutions with participants as informed by the formal consultation process and any subsequent stakeholder discussions.

3.5.3 Clarification of continuous uninterrupted operation in the range 90% to 110% of normal voltage

Ref.	Group	Standard type	Objective(s)
#67	General	AAS and MAS	• Streamline the connection process • Support efficient investment and operation

Description

NER S5.2.5.4(a)(6) requires a generating system or IRS to be capable of continuous uninterrupted operation where a power system disturbance causes the voltage at the connection point to vary within 90%-110% of normal voltage 'continuously'. Continuous uninterrupted operation is defined as follows:

> ***continuous uninterrupted operation***
>
> In respect of a *generating system* or *generating unit* operating immediately prior to a *power system* disturbance:
>
> (a) not *disconnecting* from the *power system* except under its *performance standards* established under clauses S5.2.5.8 and S5.2.5.9;
>
> (b) during the disturbance contributing active and reactive current as required by its *performance standards* established under clause S5.2.5.5;
>
> (c) after clearance of any electrical fault that caused the disturbance, only substantially varying its *active power* and *reactive power* as required or permitted by its *performance standards* established under clauses S5.2.5.5, S5.2.5.11, S5.2.5.13 and S5.2.5.14; and
>
> (d) not exacerbating or prolonging the disturbance or causing a subsequent disturbance for other *connected plant*, except as required or permitted by its *performance standards*,
>
> with all essential auxiliary and *reactive plant* remaining in service.

The wording of NER S5.2.5.4(a)(6) has not been interpreted in the same way across the NEM. The interpretation of the clause has significant cost implications for IBR plant because, as these devices are current-limited, the apparent power rating is a function of voltage.

AEMO published a clarificatory document in 2018[26], which interpreted CUO to require the generating system to be capable of maintaining its active and reactive power when the voltage at the connection point drops to 90% of normal voltage, as failure to do so may result in (among other things):

- Compromised voltage stability.
- Active power changes as a result of voltage changes that might impact frequency.

The document suggested an assessment methodology that required a step in voltage from the normal operating voltage of the generating system down to 90%. This methodology is site-specific, with requirements depending on the connection point operating voltage. A generating system having a connection point operating voltage of 107% would be required to have capability to maintain is active and reactive power for a 17% step, whereas a system having a connection point operating voltage of 100% would be subject to a step of 10%. The wider range increased the number of inverters required significantly compared with the narrow range, raising a question of equity and efficient investment. This methodology also exposes the Generator to particular compliance concerns over time, if the operating voltage of the connection point increases over the life of the plant, beyond the level for which the plant was originally designed.

More recently some TNSPs have adopted methodologies that require a 10% change, including to 90% of normal operating voltage, the lowest voltage of the range for NER S5.2.5.4(a)(6). A 10% change is consistent with TNSP obligations under NER S5.1.4 which require the TNSP to plan and design is transmission system and equipment for control of voltage such that the minimum and maximum steady state voltages, and variation in voltage magnitude are consistent with the levels stipulated in NER S5.1a.4 of the system standards. The system standards state that the supply should not vary by more than 10 percent above or below its normal voltage,

[26] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Transmission-and-Distribution/Clarification-of-S525-Technical-requirements.pdf

except as a consequence of a contingency event. A 10% reduction from 100% to 90% of normal voltage would result in the most onerous requirement for a 10% variation in the range described by NER S5.2.5.4(a)(6).

Since the consideration is for reactive and active power capability in this instance, the variation could be a ramp rather than a step. The intention is that the capability should be provided continuously, rather than relying on the time for tap changer operation to return the reactive capability to its maximum steady state level. For this reason, AEMO suggests a 2 second timeframe for assessing the variation in voltage. Some plant may not be able to remain stable for a step of 10%, whereas they should be able to tolerate a ramp over 2 s. AEMO would welcome feedback on whether this is an appropriate timeframe, considering the test would apply in the minimum and automatic access standards.

Some plant may utilise overload capability in conjunction with tap changing to achieve this requirement. In this case, the overload capability would need to be sufficient to maintain the active and reactive power continuously over the required tap changes, so that active and reactive power capability are maintained continuously, during and following the ramp.

However, workshop participants reported that, across the NEM, there is not consistency in how the rule and methodology are applied.

Discussion and feedback

AEMO did not initially identify this as an issue in the approach paper. However, it was raised by participants in workshops that discussed issues around NER S5.2.5.4 and continuous uninterrupted operation. AEMO considers that there is value in achieving consistency in the application of this rule. AEMO has therefore included it in the draft report, based on this feedback.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Specify that for the purposes of NER S5.2.5.4(a)(6) subject to energy source availability, reactive capability must be maintained, and active power not substantially reduced, for voltages in the range 90 to 110% of normal voltage for voltage variations up to 10%, (assessed as a ramp over 5 seconds) within the reactive power range and voltage range specified in S5.2.5.1.

Option 2 provides a consistent way of determining the requirements for achieving continuous uninterrupted operation, which balances cost to proponents and the needs of the power system.

Recommendation

AEMO recommends Option 2.

3.6 NER S5.2.5.5 – Generating system response to disturbances following contingency events

The approach paper identified several issues with NER S5.2.5.5, which are examined in this section. Relevantly, NER S5.2.5.5:

- defines the requirements for generating system response to credible contingency events and non-credible contingency events including multiple disturbances;
- defines the reactive current injection and absorption requirements during faults, and active power recovery following faults; and
- describes requirements for responses following recovery from faults, in conjunction with the CUO definition.

In December 2022, the AEMC published a draft rule determination[27] concerning aspects of reactive current injection, predominantly looking at the MAS for reactive current injection and active power recovery. Some of the draft rule changes also affect the AAS for NER S5.2.5.5.

3.6.1 Definition of end of a disturbance for multiple fault ride through

Ref.	Group	Standard type	Objective(s)
#20	General	AAS/MAS	• Streamline the connection process

Description

NER S5.2.5.5 multiple fault ride through requirements were introduced in 2018, following a black system event in South Australia in 2016[28]. In that event, several wind farms tripped after three faults occurred within a relatively short time frame (less than five minutes) because of a protection based on a fault counter. The presence of the fault counter was not recognised during the connection process and the tripping was not anticipated.

Both the AAS and MAS for NER S5.2.5.5 describe requirements for generating system multiple fault ride through (MFRT), provided each fault or sequence of faults meets a set of conditions. MFRT for up to 15 prescribed faults is required in the AAS. The AAS states that the minimum clearance from the end of one disturbance and the commencement of the next disturbance for the AAS may be zero milliseconds (ms). Similar wording in the MAS nominates 200 ms.

NER S5.2.5.5 does not define what constitutes the end of a disturbance. As a consequence, it is possible to interpret the AAS to require ride through of 15 faults consecutively where there is no recovery of voltage between them. The probability of this occurring is very low[29] and such an interpretation would be unnecessarily onerous, posing an impediment for connection.

Even if this onerous interpretation is not applied, the lack of clarity on the delineation between one disturbance and the next can result in a prolonged negotiation process. Providing certainty should make the connection process more efficient and therefore less expensive.

While this issue is most apparent in the AAS, it also applies to the MAS.

Discussion and feedback

This issue was raised via consultation on the New South Wales Central West Orana Renewable Energy Zone access standards. Under this Review, it was discussed in prioritisation workshops, and a subsequent options

[27] AEMC, Efficient reactive current access standards for inverter-based resources, Draft rule determination, 15 December 2022, at: https://www.aemc.gov.au/rule-changes/efficient-reactive-current-access-standards-inverter-based-resources.

[28] AEMO, "Black system South Australia 28 September 2016" March 2017 At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf.

[29] There are numerous examples of events where multiple faults have occurred on the power system within a small geographical area within a five minute period. Bushfires often result in faults in close proximity both temporally and electrically. This is a different situation from having 0ms between each fault.

assessment workshop facilitated by AEMO. In both Review workshops there was a high level of support for addressing the issue. In the prioritisation workshop just one stakeholder opposed the change but did not provide any reasoning.

Options

The options considered to address this issue were:

1. Do nothing.
2. Define the end of the disturbance as the time when the fault clears.
3. Define end of the disturbance as when, following fault clearance, the voltage recovers to the range 90% to 110% of normal voltage at the connection point.
4. Define the end of the disturbance as when, following fault clearance, the voltage recovers to the range 90% to 110% of normal voltage at the connection point and remains within this range for a specified minimum time.
5. Define the end of the disturbance as when, following fault clearance, the voltage recovers to the range 90% to 110% of normal voltage at the connection point and, unless the generating system is the cause of further excursions outside of the range 90% to 110%, remains within this range.

Option 1 is not recommended given the high level of support for addressing the issue.

Option 2 specifies fault clearance as a necessary pre-condition for the end of a disturbance. Although simple this does not resolve the issue, because it still allows for the interpretation that it includes continuous faults.

Option 3 and Option 4 inherit the fault clearance condition from option 2 but provide some distinction between consecutive faults. Option 4 also requires the response to remain within the band for normal operation, although in practice there are frequently disturbances within this band too. Option 4, because of the minimum time to ascertain that something remains in the range of 90% to 110% of normal voltage, implies a (slightly) longer duration between faults.

Option 5 addresses a possible issue where the generating system might be the cause of a disturbance being prolonged, in which case poor behaviour of the generating system might extend the calculated time between faults. This has more potential to be manifest in Option 4, where the definition includes remaining within the normal voltage range. This issue is partially mitigated by the CUO requirement in which the post-disturbance behaviour is required to be adequately damped. This means that in most cases the disturbance will be within the normal operating band within the first swing. In most cases tuning of asynchronous plant can achieve post-fault responses that are well-damped. Less damped response is also more likely for synchronous machines, which may not be able to meet the automatic access standard in any case, because of critical clearing time.

Option 5, which qualifies the qualification, results in a more complex formulation. To assess this would require duplication of studies, with and without the generating system's operation during the fault. The additional work does not seem warranted and would increase the time and effort required for connection.

Recommendation

AEMO recommends an amendment to NER S5.2.5.5 to give effect to Option 4. Specifically, this would specify that the end of a power system disturbance, for the purpose of MFRT assessment, is the time when, following fault clearance, the voltage recovers to and remains for at least 20ms within the range 90 to 110% of normal voltage at the connection point.

This is similar to what the AEMC has currently proposed for the MAS in its Draft Determination on Efficient reactive current Access standards for IBRs, and is consistent with AEMO's submission to that Draft Determination.

3.6.2 Form of multiple fault ride through clause

Ref.	Group	Standard type	Objective(s)
#21	General	AAS & MAS	• Streamline the connection process • Improve power system resilience

Description

The MFRT clauses of NER S5.2.5.5 require plant to remain in CUO for a series of up to 15 disturbances and 6 disturbances within a five-minute period in the AAS and MAS respectively, provided a range of conditions are satisfied. The cumulative duration, the number of three phase faults, and a limit on the time integral within any five-minute period of the difference between 90% of normal voltage and when the voltage at the connection point is lower than 90% are all specified.

These requirements make assessment a very academic exercise, but nevertheless, leave potential for a very large number of possible combinations of faults. From the perspective of simulation, exhaustive testing is potentially very time consuming and expensive, and it is generally only possible to prove non-compliance, and not prove compliance.

The modelling also does not and cannot capture all types of conditions that might cause a plant to trip, for example, mechanical resonance conditions that can arise from some combinations of faults (and particularly unbalanced-fault temporal spacing). This type of issue is modelled in entirely different modelling software from that used in power system simulations. There are other limitations that could possibly be modelled approximately, such as thermal limits and energy-related limits, but practically, some of these conditions require inputs that are beyond those used in power system analysis tools, and approximating them would not significantly increase the confidence in modelling outcomes.

Technical requirements should reflect that power system modelling may not reveal whether a plant has limitations that would prevent it from riding through multiple faults. From the perspective of the power system operator, prior knowledge of conditions under which plant is expected to trip is important, because it allows the system operator to assess more accurately the risk of multiple trip events, where weather or other abnormal conditions suggest a higher probability of multiple faults.

A consequence of the formulation of NER S5.2.5.5, and particularly the MAS, is that there is no explicit requirement or incentive to disclose limitations. As modelling is time consuming and requires analytical effort, there is also value in minimising the number of simulations required, but with the present formulation this is at the expense of confidence level around compliance.

Discussion and feedback

Participants in the prioritisation workshop placed a very high priority on addressing this issue. Discussion in the options assessment workshop indicated a high level of consensus for more flexibility in the MAS and a requirement to disclose limitations including those not observable in power system models.

There was less agreement regarding the form of a standard that both promotes the capability of plant for MFRT and is practical from a compliance perspective. Some participants advocated complete redrafting, whereas others preferred to focus on fixing the MAS.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Require disclosure of limitations on MFRT in the MAS and evidence to support them; and MAS requirement excluding those limitations.
3. Require NSP to define test cases to assess, relevant to the network at the connection point and protection clearance times. Compliance would be assessed based on the outcome of the tests, subject to model being sufficiently accurate to demonstrate compliance.
4. Allow Hardware in Loop (HIL) testing as an alternative form of compliance testing. The NSP would also need to agree the tests with the connection applicant in this case.
5. Provide for AEMO to define a common suite of tests that would exercise the models for MFRT. These tests could be adjusted for the fault level range of the connection point. The connection applicant could demonstrate compliance by simulating the generating system response to the suite of tests, provided model alignment to plant is considered sufficient to represent its compliance correctly. For the MAS, any limitations not modelled would also need to be declared. If required, the minimum fault level during the test may be adjusted to be above the minimum fault level required by the NSP for tuning (see Section 3.6.4 of this report).

Option 1 is not preferred as it would not address an issue that industry considers high importance.

Option 2 for the MAS is well supported and logical from an operational perspective.

Option 3 and Option 5 retain the modelling aspect of NER S5.2.5.5 by exposing, through simulation, some deficiencies of plant models which may reflect actual deficiencies in controls that can be improved by this modelling process. Improved plant performance via this requirement is the key benefit of the clause as written.

Option 3 relies on the model for compliance, and therefore has some uncertainty. However, this is not different to the present situation. Option 3 is better than the current arrangement in that it is more likely to test the most relevant and onerous cases that are relevant to the connection point, rather than a scattergun approach. A disadvantage is that it would require resources from the NSP and potentially a significant time delay to the project, as the NSP would have to investigate and prepare a site-specific set of study cases for each connection.

For Option 4, HIL testing would need to be undertaken with the settings and firmware consistent with the plant to be installed. This means that it is likely to be site-specific. The use of site-specific tests could introduce delays into the connection process, because test facilities are limited. The number of tests might also need to be more limited than a simulation suite because of the cost and resource required. The time and cost considerations limit the practicality of this option.

In Option 5 the model is run on the test suite, and satisfactory results would be evidence of having sufficient MFRT capability for the automatic access standard (unless there are non-modelled limitations declared). The test suite could incorporate the MFRT requirements embedded in the current AAS and MAS, and be applied on a single-machine infinite bus system with the fault levels appropriate to the connection point. Conceptually the test suite would be adjustable to the range of fault levels nominated for the plant tuning by the NSP, by means of a script.

The proposed compliance assessment for Option 3 and Option 5 differs from the present rule, in that it proposes to deem compliance, based on the outcomes of simulations (in conjunction with declared impediments) rather than based on future performance. This change affects the risk allocation among parties. AEMO has the overall responsibility for operating the power system. It is therefore in AEMO's interest that plant operation is as robust as possible to the types and combinations of disturbances that might occur. It is also important that the limitations of the plant are properly understood, so they can be taken account of for operation of the system. Options 3 and 5 are most likely to achieve these outcomes. Making the plant operator accountable for performance does not appreciably increase the likelihood of better performance than can be achieved through Options 3 or 5.

Because the compliance is reliant on the modelling results, for options 3 and 5 it is necessary to make the compliance subject to there being alignment between the model and the test results. This option does not mandate HIL tests, but they would help to provide confidence in the plant's compliance.

If the plant cannot satisfactorily demonstrate compliance with the test suite in Option 3 or Option 5, then further investigation would be required to demonstrate a negotiated level of access.

Ongoing compliance would review any tripping of the plant to see whether it is consistent with declared limitations. Failure to declare either a modelled or non-modelled limitation would be considered a non-compliance.

Option 5 would have advantages of:

- Being relatively quick and simple to set up and run the simulations (compared with the current process or Option 3), making the process more efficient;
- Allowing AEMO to specify tests that it considers would adequately demonstrate MFRT performance.
- Establishing a pathway that manages compliance risk for the generator, while also giving AEMO and the NSP confidence that the plant is fit to be connected to the power system;
- Providing an incentive to tune plant well to meet the AAS level of tests; and
- Providing an incentive to disclose any non-modelled limitations.

Recommendation

AEMO recommends Option 2 and 5, which provide the best combination of characteristics of those options considered. It comprises:

- a suite of tests, established by AEMO, incorporating the MFRT requirements under the AAS and MAS;
- a requirement on the proponent to apply the tests considering the range of fault levels nominated at the connection point by the NSP, and using the site-specific settings proposed for the plant;
- a requirement on the proponent to declare in proposed performance standards any impediment to MFRT, and provide evidence to support the declaration;
- a requirement that compliance with the performance standard is to be demonstrated by performance against the test suite and, throughout the life of the plant, not tripping for any undeclared impediment, checked by verifying the cause of any applicable trips during multiple disturbance events.

3.6.3 Number of faults with 200 ms between them (MAS)

Ref.	Group	Standard type	Objective(s)
#66	General	MAS	• Align with best power system performance • Streamline the connections process

Description

The MAS for MFRT currently requires the plant to remain in CUO for up to 6 faults that are 200ms or more apart, within a 5-minute window, subject to a set of criteria about the fault combinations.

As previously discussed, some of the limitations that cause a plant to trip may not be modelled in power system modelling software. In addition, there may be some plant that cannot comply with the MAS. The limitation may, in some cases, relate to the time between consecutive faults rather than the total number of faults.

It is beneficial for generating systems and IRSs to ride through multiple faults, as this increases the resilience of the power system, and lowers the risk of loss of supply in extreme weather events. As mentioned in the previous section of this report, the MFRT provisions improve the performance of plant by exposing through simulation some deficiencies of plant models which may reflect actual deficiencies in controls that can be improved by this process. This is the key benefit of NER S5.2.5.5 as written.

On the other hand, failure in simulation to ride through a particular combination of fault conditions should not be automatically an impediment to connection of a plant, unless the risk associated with the failure (considering likelihood and potential impact on the power system) is significant. For example, if a 500 MW plant cannot ride through three faults in a row, that would be a significant risk, whereas if a 5 MW plant had this limitation, it is highly unlikely to affect the resilience of the power system. A 500 MW plant that could not ride through three unbalanced faults precisely two seconds apart, because of a mechanical resonance condition would also be low risk, as the likelihood of this fault sequence occurring is very low.

Discussion and feedback

As described in the previous section, workshop participants supported providing flexibility in the MAS, and the requirement to declare impediments.

Options

The options considered to address this issue were:

1. Do nothing.
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.
3. Allow a reduced minimum number of faults in general (e.g. 3), retaining the minimum 200 ms gap and other combination criteria, and specific carve outs.
4. Leave requirement for six faults but make the time between them flexible.
5. No specific requirement.

Option 1 is not preferred as it does not address the issue.

Option 2 would be consistent with the proposed option for the form of the clause (see section 3.6.2 of this Report). Under this option, MFRT for six faults 200 ms apart would be required apart from carve outs for specific conditions.

Option 3 could also work with the proposed option for the form of the clause, but would be a substantially lower requirement.

Option 4 would allow faults as far apart as 50s, but also as close together as allowed by the 'end of disturbance definition'. This would be more onerous than the existing MAS.

Option 5 is completely flexible but could not be included in test suite.

Recommendation

AEMO recommends Option 2, that is for the MAS requirement to remain up to six faults separated by at least 200 ms and combination criteria (in the form proposed in section 3.6.2 above), but allow specific limitations such as technology-related limitations (but not limitations arising from inadequate tuning) to be carved out of these requirements for modelled and non-modelled limitations. This allows flexibility while minimising the carve outs from present requirements. It also promotes efficient connection as it can be programmed into the common test suite proposed in section 3.6.2 above.

3.6.4 Reduction of fault level below minimum level for which the plant has been tuned

Ref.	Group	Standard type	Objective(s)
#22	General	AAS & MAS	• Streamline the connection process

Description

Most technical standards are studied considering fault levels applying for system normal and single outage conditions, for a range of generation dispatch conditions. MFRT is different, in that it considers non-credible combinations of conditions. Currently, the MFRT rule excludes material reductions of power transfer capability from the conditions for which the plant must remain in CUO, but does not contemplate that multiple faults could reduce the fault level at the connection point below the level for which the plant was tuned.

Discussion and feedback

There was less support and a greater diversity of views on this issue than the other MFRT issues. Some participants at the prioritisation workshop indicated that including a carve out for conditions below minimum fault level for which the plant is tuned would make assessment more arduous, because they would have to assess the fault level after the multiple fault sequence, and questioned how this could be achieved in a single machine infinite bus model. AEMO considers that multiple faults will often lead to changes in fault level, when lines are tripped to clear faults. The fault sequence may lead to lower fault level unless all lines tripped during the sequence are also reclosed as part of the sequence. Failure to consider changes in fault level could lead to overly optimistic results for MFRT assessments.

Generally, generating systems and IRSs will tend to become less stable for operation at lower fault levels and may not be able to remain in CUO for a materially lower fault level than that for which they were tuned.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Carve out fault level below range for tuning of the plant, nominated by the NSP from the conditions for MFRT.
3. Option 2, and record the range of fault levels in the performance standards (for NERS5.2.5.5 and S5.2.5.13).
4. Option 2, and record the range of fault levels in association with the performance standards (but not within them), for example, in the releasable user guide.
5. Require the plant to operate stably and remain connected, for fault level below the tuning range (consistent with the wording of NER S5.2.5.15 down to the SCR level specified in NER S5.2.5.15).
6. Additionally require that if the NSP determines that the lower limit of the range of fault levels for the connection point has reduced such that there is a risk that the plant will not be able to be compliant for the multiple disturbance test suite or other contingencies when the new lower limit of fault level is applied, then this shall be considered sufficient reason to require settings changes under NER S5.2.2.

Option 1 is not preferred as it represents a compliance risk for the generator beyond its control.

Option 5 may be problematic, because NER S5.2.5.15 allows for different settings to be used to demonstrate compliance at that low level.

Option 2 is consistent with AEMO's preferred policy of not recording settings in performance standards, which would make it easier to change the tuning range later but makes it difficult for a Generator or IRP to demonstrate compliance later, if the tuning range is not documented in the GPS.

Option 3 is most preferable from the perspective of demonstrating ongoing compliance, but changing the specified tuning range would trigger a NER 5.3.9 process, rather than a NER S5.2.2 process. Option 4 is similar to Option 3, but does not trigger a 5.3.9 process.

Carving out a requirement to remain in CUO for fault level less than the minimum tuned value does not mean necessarily that the plant will not remain in operation, but it might be less stable and not meet all the conditions for CUO. Considering Section 3.6.2, this could be achieved by applying the range of fault levels to the test suite for multiple fault ride through. The carve out would be described as one of the rules that AEMO would apply when creating the test suite.

A consequence of recording the fault level range is that tripping outside the fault level range nominated by the NSP would not be a non-compliance. The logical approach to potential operation outside the range of fault levels for which the plant has been tuned is to retune for the correct range. However, the trigger for the NSP to require a setting change in NER S5.2.2 is a non-compliance, which would not be present in this case. Option 6 addresses this issue, so that a change in the fault level range of the power system can be a trigger for the NSP to require settings changes in the plant, to bring the tuning range of fault levels in line with the power system's operation.

Recommendation

AEMO recommends NER amendments to give effect to Options 4 and 6.

3.6.5 Active power recovery after a fault

Ref.	Group	Standard type	Objective(s)
#25	General	AAS	• Streamline the connection process

Description

The CRI proposed an amendment to the existing active power recovery clause to one where active power recovery should be assessed from the time that the voltage recovers to within 90% to110% of normal voltage. This would be consistent with the behaviour of plant that has low voltage ride through (LVRT) thresholds, as below LVRT the plant is expected to prioritise reactive power over active power and, therefore, if the voltage does not recover to 90% the active power might not either. This recommendation has been adopted for the MAS in the AEMC's draft determination on the efficient reactive current access standards for IBRs[30].

Another potential advantage of this proposal is that, if the system is much weaker following the clearance of a fault, it might be destabilising to inject active power rapidly since it could adversely affect voltage stability.

Changing both the AAS and MAS would therefore better align the clause with best performance on the power system, as well as contributing to streamlining the connection process.

Transgrid, in its feedback on the approach paper, suggested that the recovery be considered for 'the first instance at' which the active power reaches 95% of pre-fault level, for clarity. It also considered that the application of active power recovery requirements to bi-directional systems, as introduced by the IESS Rule, might be ambiguous and need reviewing.

The relevant rule is NER S5.2.5.5(f)(3)

(f) Subject to any changed *power system* conditions or energy source availability beyond the *Generator's* reasonable control, a *generating system* comprised of *asynchronous generating units*, in respect of the types of fault described in subparagraphs (c)(2) to (4), must have *facilities* capable of supplying to or absorbing from the *network*:

(3) from 100 milliseconds after clearance of the fault, *active power* of at least 95% of the level existing just prior to the fault.

The AEMC's draft determination for the MAS equivalent to this clause is:

(n) Subject to any changed *power system* conditions or energy source availability beyond the *Generator's* reasonable control, a *generating system* comprised of *asynchronous generating units* must: …

(2) return to at least 95% of:

(i) the pre-fault *active power* output; or

(ii) during a frequency disturbance, a level of *active power output* consistent with the *generating system's performance standard* under clause S5.2.5.11,

after clearance of the fault and recovery of positive sequence *voltage* at *the connection point* to be stable between 90% and 110% of *normal voltage*, within a period agreed by the *Connection Applicant*, *AEMO* and the *Network Service Provider*, which period may differ according to the type of fault.

[30] At https://www.aemc.gov.au/rule-changes/efficient-reactive-current-access-standards-inverter-based-resources.

AEMO's response to the draft determination consultation suggested rather than a requirement for the voltage "to be stable" that the condition be that it was required "to remain", as this allows for a simpler assessment of the starting point for the time for active power recovery.

AEMO also suggested noting in (ii) above, that the clause should also refer to primary frequency response (PFR) provision under NER 4.4.2(c1) and other types of frequency/angle responses that are more likely to occur in the time frames considered for fault recovery. From a GFM inverter perspective, if there is a change in phase angle on clearance of the fault, the generating units will oppose that change, which will introduce a transient active power change. Some other asynchronous technologies may also oppose a phase angle jump. This is a beneficial performance characteristic that should be permitted. A supply – demand imbalance that would lead to a frequency change can also trigger an inertial response from a GFM inverter or other asynchronous technology with synthetic inertia enabled.

Discussion and feedback

During the prioritisation workshop, participants indicated a high level of support for addressing the consideration of voltage in the assessment of active power recovery. No participant opposed the change.

AEMO did not facilitate an options assessment workshop for this issue as the incorporation of voltage consideration in the active power recovery assessment was workshopped through the AEMC's technical working group for ERC0272 relating to NER S5.2.5.5.

The reference to NER S5.2.5.11 in the draft NER S5.2.5.5(n)(2)(ii) above was from the CRI submission on the rule change proposal, and was not discussed in the AEMC workshops.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Incorporate the changes made for the MAS into the equivalent wording for the AAS.

Recommendation

AEMO recommends Option 2, that is to change the AAS, substantially consistent with the MAS changes, subject to minor amendments proposed by AEMO in response to the ERC0272 draft determination, noting that the final determination has not yet been published. In the final report for this Review, consideration will need to be given to how AEMC's final determination deals with frequency response, inertial response and active power response to phase angle changes.

3.6.6 Rise time and settling time for reactive current injection

Ref.	Group	Standard type	Objective(s)
#28 / #54	General	AAS	• Align with best power system performance • Streamline the connection process

Description

The reactive current rise time and settling time requirements on asynchronous production units for reactive current injection during a fault are intended to achieve fast, stable response during faults. Reactive current during a fault or voltage disturbance:

- Assists the generating system or IRS to remain in service during a fault or overvoltage event.
- Provides voltage support to the local network that can assist voltage stability of the power system.

The AAS requires that the reactive current response has a *rise time* of 40ms, a *settling time* of 70 ms and be *adequately damped*, where rise time, settling time and adequately damped are defined[31] as follows:

> ***rise time***
>
> In relation to a *control system*, the time taken for an output quantity to rise from 10% to 90% of the maximum change induced in that quantity by a step change of an input quantity.
>
> ***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, the maximum change induced in that output quantity; or
>
> (b) the sustained change induced in that output quantity.
>
> ***adequately damped***
>
> In relation to a *control system*, when tested with a step change of a feedback input or corresponding reference, or otherwise observed, any oscillatory response at a frequency of:
>
> (a) 0.05 Hz or less, has a damping ratio of at least 0.4;
>
> (b) between 0.05 Hz and 0.6 Hz, has a halving time of 5 seconds or less (equivalent to a damping coefficient –0.14 nepers per second or less); and
>
> (c) 0.6 Hz or more, has a damping ratio of at least 0.05 in relation to a minimum access standard and a damping ratio of at least 0.1 otherwise.

AEMO and stakeholders have identified the following issues with these criteria:

- The terms rise time and settling time relate to step changes, but have been applied to fault responses where the voltage input may not be a step or even step-like.
- The assessment band for the settling time definition depends on the magnitude of the response. For a shallow fault the small voltage change can give rise to an error band that is too small for a meaningful assessment of settling time. In effect, test criteria have been defined that depend on inputs, but the input has not been adequately specified.

[31] In chapter 10 of the NER.

- Especially in high system impedance conditions, the reactive current response is likely to influence the voltage measured at the unit's terminals. This is expected, but even in simulations, makes the voltage and response less step-like.
- In some types of technology, including GFM inverters, the response may not settle over the time of the fault, due to slower dynamics of the control systems occurring during the fault. This is not an indication of an incorrect response. The response may be acceptable and adequately controlled, but arguably it is the assessment criterion that is not fit for purpose.
- The rise time measurement can also be affected if the response during a fault does not settle, as it depends on the maximum change. For instance, the response might rise rapidly, flatten, then rise again, which can affect the rise time calculation.
- The reactive current response is required under NER S5.2.5.5 to be directly proportional to the voltage change, but the voltage profile itself may not be adequately damped according to the definition. It is therefore inappropriate to use the term adequately damped in this context.
- In addition, even when a simulated fault is step-like, if the fault is unbalanced the measured voltage including positive and negative sequence elements may not satisfy the 'adequately damped' criterion, even when it is an entirely satisfactory response.

The MAS has a similar form, and is the subject of an active rule change process being progressed by the AEMC on the efficient reactive current access standards for IBRs[32]. The issues described above are also relevant to the MAS.

In its draft determination, the AEMC has proposed for the MAS:

- Increasing risetime from 40 to 80 ms, with provision for longer rise time with agreement of the NSP and AEMO.
- Omission of settling time.
- Requiring the response to be adequately controlled, rather than adequately damped.
- Proposing a new requirement for commencement time of less than 40 ms.

Discussion and feedback

Stakeholders at the prioritisation workshops rated this issue as very high importance. The issue was also discussed in detail at an options assessment workshop, where participants continued to support changes to the NER relevant to this issue.

Options

The options considered to address this issue were:

1. Do nothing.
2. Omit settling time for AAS.
3. Keep settling time, but specify conditions for assessment.
4. Add adequately controlled instead of adequately damped.

[32] At https://www.aemc.gov.au/rule-changes/efficient-reactive-current-access-standards-inverter-based-resources.

5. Qualify rise time to be measured for "step-like" voltage profile at unit terminals.
6. Add to AAS commencement time, <10ms, with response in a direction that opposes the change in voltage.

These options, discussed in the Options Assessment workshop[33], are mostly not mutually exclusive, except for Option 2 and Option 3. Most workshop participants supported Option 3 over Option 2, consistent with the proposed rule changes in the draft determination. Two participants suggested 20 ms commencement time, compared with the 10 ms proposed above. However, AEMO has undertaken investigations that suggest that GFM inverters and at least some modern grid following (GFL) inverters, which have voltage response that can assist in maintaining system strength, can achieve response commencement time less than 10 ms. A rapid commencement of response in a direction that opposes the change in voltage is important for stiffening the voltages on the power system. AEMO therefore prefers 10 ms as an automatic access standard as this is consistent with better performance on the power system than 20 ms. Option 5, for quality risetime to be measured for "step-like" voltage profile at the unit terminals, also received strong support. This is additional to the proposed amendments in the AEMC draft determination.

Generally, the options supported by workshop participants align with the achieving good performance on the power system, because a fast response that is well controlled will manage voltages during faults better than a slow response in most circumstances. The qualification that rise time is measured for a step like response means that assessments will be only made for situations in which the calculation of risetime is meaningful. This should make the assessment process more efficient. Omission of settling time and the qualification of the risetime calculation could also reduce regulatory risk for Generators and Integrated Resource Providers concerning compliance assessment for non-step like faults.

Recommendation

Consistent with the positions of options assessment workshop participants, AEMO recommends Options 2, 4, 5 and 6. This comprises the following amendments:

- Omit settling time for the AAS.
- Replace 'adequately damped' with 'adequately controlled'.
- Qualify that rise time is to be measured for "step-like" voltage profile at the production unit terminals.
- Add a commencement time requirement, less than 10 ms, with response in a direction that opposes the change in voltage at the production unit terminals.

3.6.7 Commencement of reactive current injection

Ref.	Group	Standard type	Objective(s)
#27	General	AAS	• Align AAS with best power system performance • Remove impediments for GFM inverters (to meet AAS)

[33] In the workshop this issue was combined with other issues, but is separately discussed in this report. Note that, as a result, the option numbers changed compared with the workshop numbering.

Description

At present, the AAS for an asynchronous generating system under NER S5.2.5.5(g)(1) requires that the reactive current response for an undervoltage commences in an under-voltage range 85% to 90%, and an overvoltage range 110% to 115%, of normal voltage on the connection point.

The intended effect of this clause is for reactive current injection to start as close to normal voltage as possible to manage voltage excursions quickly. However, the clause implicitly assumes that the plant has a LVRT threshold, and a two-tier control-strategy whereby voltage control passes from power plant controller to the production unit for reactive current injection during a fault.

In practice, not all asynchronous systems operate in this way: some have response based on the magnitude of the voltage change rather than the voltage threshold. Some, like GFM inverters, respond instantaneously to oppose a change in voltage. In addition, while two-tier voltage control is common, and encouraged by some of the generator technical standards (especially NER S5.2.5.13) it is not necessarily the best strategy for low system strength conditions. For these types of controllers, the present AAS and MAS are not appropriate owing to the technology-specific form of the clause.

The clause is also not written in a way that promotes best power system performance. Response that arrests the change a voltage disturbance more quickly and closer to the pre-disturbance value will provide a better outcome for the power system, whereas the current standard provides an upper bound on the response commencement.

The five-percent range in practice does not work for most generating systems or IRSs that have a step up transformer with on-load tap-changer between the production units and the connection point. This is because there is a difference in the voltage at the connection point compared with the unit terminals that changes as a function of the tap position and the active and reactive power output of the generating system or IRS. A five-percent range is often not practically achievable for a medium or large system with reactive power range consistent with the AAS of NER S5.2.5.1. It is typically achievable for systems connected directly to the power system without an intervening step-up transformer. Although the rule as written allows for a different range to be agreed provided the range still has a five-percent band between upper and lower voltages, this does not address the practical issue.

The MAS has the same fundamental problems, but just a wider range. The issue is included in the AEMC’s ongoing efficient reactive current access standards rule change process. In the draft determination, the AEMC proposed to remove the upper voltage of the band, so that commencement is (for the minimum access standard) above 85% of connection point voltage, and below 115% for an overvoltage.

Discussion and feedback

There was strong support in the prioritisation workshop for addressing this issue. There was a variety of views about whether technology neutrality was necessary. However, AEMO considers that this is a good example of where the absence of technology neutrality can lead to unintended consequences that impede better control options.

Options

The options considered to address identified issues were:

1. Do nothing.

2. Specify that reactive current response needs to commence above a voltage level at the connection point (85% of normal voltage) for an undervoltage event, and below a voltage level (115% of normal voltage) for an overvoltage event.

Option 1 would not address the issue. Option 2 is consistent with the AEMC's proposed approach in the Draft Determination. It was workshopped for the MAS in the AEMC's technical working group, and also as part of the options assessment. The proposed option received strong support in both the AEMC and AEMO workshops.

It should be noted that if the plant needs to change to a different mode of operation for low voltage mode, this does not mean that other performance requirements like frequency response or active power dispatch requirements do not apply. Setting any LVRT threshold too high, such that it could encroach on operational voltage without a disturbance, might result in inability to meet other performance standards, and would need to be avoided.

Recommendation

AEMO recommends amendments to give effect to Option 2.

3.6.8 Clarity on reactive current injection volume and location and consideration of unbalanced voltages

Ref.	Group	Standard type	Objective(s)
#23/ #24	General	AAS	• Streamline connections process • Align with best power system performance (AAS)

Description

NER S5.2.5.5(f) for the AAS requires that a generating system or IRS comprised of asynchronous production units must have facilities capable of supplying or absorbing from the network, to assist the maintenance of power system voltages during a fault:

(i) capacitive reactive current in addition to its pre-disturbance level of at least 4% of the maximum continuous current of all operating *asynchronous generating units* of the *generating system* or *integrated resource system* (in the absence of a disturbance) for each 1% reduction of *voltage* at the *connection point* below the relevant range in which a reactive current response must commence; and

(ii) inductive reactive current in addition to its pre-disturbance level of at least 6% of the maximum continuous current of all operating *asynchronous generating units* of the *generating system* or *integrated resource system* (in the absence of a disturbance) for each 1% increase of *voltage* at the *connection point* above the relevant range in which a reactive current response must commence.

The base for the current percentage calculation is the maximum continuous current. There is no definition of this quantity in the present technical standards, but in its draft determination on the efficient reactive current access standards for IBRs, the AEMC proposed to define maximum continuous current as:

> *maximum continuous current*
>
> In respect of a *generating system* the current at the *connection point* corresponding to the largest amount of apparent power required by the *generating system's* performance standard under NER S5.2.5.1, at the *normal voltage*.

The base for the voltage percentage is the base voltage of the connection point (its *normal voltage*). Relevant NER provisions also allow for a different location to be agreed with AEMO and the NSP for the measurement of this quantity, in which case the voltage base would be relative to that location's nominal voltage.

The amount of reactive current injection/absorption affects:

- the ability of a generating system or IRS to remain online during under-voltage or over-voltage events; and
- the level of voltage support provided by the generating system to the power system in the local area during voltage disturbances.

Reactive current injection beyond maximum continuous current is not required and IBR plants typically have a current limit, so for deep faults, plants having high active current injection will typically operate at a limit for reactive current injection.

A further consideration is that the NER do not specify whether the reactive current injection should be based on positive sequence or RMS voltages including negative phase sequence. In practice, reactive current injection is generally calculated based on positive sequence voltage, and negative phase sequence is considered separately. The current limits will be based on the combined quantity. In the transmission system, unbalanced faults are more prevalent than three phase faults, so consideration of unbalanced voltages is important. Some NSPs have identified overvoltages on unfaulted phases as an issue of concern for power system voltages.

High levels of reactive injection into very high impedance networks could potentially result in voltage stability issues. High reactive current absorption can help to reduce voltage spikes on the power system quickly, but in high impedance conditions, less reactive current absorption will have the same effect on voltages than in low impedance conditions. In grid following inverters, high injection during a fault can lead to transient overvoltage as the fault clears, but before the plant responds to the changed conditions.

The level of reactive current injection or absorption at the connection point depends on the injection at the terminals and the impact of the transformers, lines and cables, and any filters connected between the unit terminals and the connection point. In particular, capacitive elements reduce their contribution with the square of the voltage.

Because of this effect, generating systems with large collector systems (especially large wind farms) may have difficulty in achieving the AAS level of reactive current injection at the connection point, or even the present MAS of 2%/% injection, without additional capital expenditure to reduce impedances of the collector system or transformer. In high fault level conditions, the installation may run into fault level limitations of equipment if low impedance transformers are used.

The drafting of the rule with the words "facilities capable of" in NER S5.2.5.5(f) and (n)(1) was intended to indicate that the facilities should be capable of the defined level of injection, but settings set to levels appropriate for the conditions at the connection point. For example, a connection where the injection level was set low to accommodate high fault level conditions initially, might have settings adjusted higher if the maximum fault level drops over time due to synchronous machine retirements. However, the drafting does not appear to have been clear enough to convey this intent, and not all stakeholders applying the technical standards are aware of the original intent.

Consideration of performance for unbalanced faults may also lead to a view that the operation of the power system is best served by prioritising negative phase sequence injection over positive phase sequence injection, at a particular location. There is potentially a trade-off between the use of reactive current to balance faults and minimise the deviation of positive sequence voltages from normal operating levels. With this prioritisation a positive sequence injection of 4%/% and absorption of 6%/% may not be achievable.

Discussion and feedback

These issues were ranked as high importance during the prioritisation workshop and were subsequently considered in greater detail during the subsequent options assessment workshop.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Retain the 4%/% and 6%/% capability requirement for facilities but clarify that the AAS requires that the settings achieve the best outcomes for plant and power system stability for the range of system impedances to which the plant may be exposed.
3. Establish an AAS requirement to minimise the voltage deviation on each phase from normal operating voltage, subject to stability criterion.
   - This implies prioritising stability and then voltage support, and would combine positive and negative sequence elements.
   - Ideally this optimisation would be at the connection point, but there is some doubt whether this can practically be achieved, since the control is at the unit terminal level.
4. Define that the reactive current injection %/% is recorded for positive sequence iq and voltage.
5. Capture the negative sequence contribution
   - Currently the requirement is to agree the ratio of negative sequence to positive with AEMO & NSP – should this change?
6. Reduce response beyond primary clearance time of nearby feeder protection (or just short of this time) to reduce overvoltages on clearance

Options 2 to 6 are not mutually exclusive and can be considered in combination.

Feedback on possible solutions from the options assessment workshop was mixed, but most participants favoured retaining the 4%/% and 6%/% for reactive current injection and absorption respectively, but clarifying that the AAS requires that settings achieve the best outcomes for plant and power system stability.

AEMO prefers to record the reactive current injection level at the connection point in the GPS as this provides a measure of performance, i.e. the extent to which the plant will provide support to the network, in addition to assisting the plant to manage its ability to ride through a fault.

Likewise, most people supported establishing an AAS requirement to minimise voltage deviation on each phase from normal operating voltage, subject to a stability criterion (option 3). This would provide the basis for the clarification to set the level of injection/absorption.

There was also support from most participants for Option 4 and Option 5, defining the percentages in terms of positive sequence voltage and current, and capturing the negative sequence contribution.

There was a wider diversity of views on specifically allowing lower injection of reactive current near primary protection clearing time to reduce overvoltages on clearance (option 6), however on balance, the approach was not supported.

Recommendation

AEMO recommends amendments to give effect to Options 2, 3, 4 and 5.

Regarding the documentation of negative phase sequence injection for option 5), Transgrid, in its feedback on the approach paper, requested that the review consider providing guidance on the expectations for unbalanced faults in terms of the positive/negative sequence components of the reactive current contribution. Transgrid noted that:

"In the absence of clear guidance in the NER, at present Transgrid's practice is to record the following three aspects in the GPS on a project by project basis:

> (i) relationship between positive/negative sequence components of the voltage vs. the sequence components of the current injection.
>
> (ii) Any current limits applicable (per-phase or on sequence component of the current).
>
> (iii) Priority (active current vs reactive current and/or positive vs negative sequence)."

AEMO would welcome feedback from stakeholders on whether this reflects an appropriate level of detail and form for the documentation of negative phase sequence injection.

3.6.9 Metallic conducting path

Ref.	Group	Standard type	Objective(s)
#46	General	Definition in NER S5.2.5.5	• Streamline the connections process

Description

S5.2.5.5(a) states that "In this clause S5.2.5.5 a fault includes a fault of the relevant type having a metallic conducting path." The statement does not appear to add clarity to the description of faults in the clause. Power system faults can generally have paths that are combinations of metallic and non-metallic conducting paths (for example an arcing fault through air). It could be argued that it potentially reduces clarity in some circumstances.

Discussion and feedback

The issue was considered low importance in the prioritisation workshop, and was not considered for the options assessment. However, as it appears to be uncontroversial and relatively simple to address, AEMO has proposed an appropriate amendment.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Remove NER S5.2.5.5(a) on the basis that existing wording does not appear to add anything useful to the clause.

Recommendation

AEMO recommends Option 2.

3.6.10 Reclassified contingency events

Ref.	Group	Standard type	Objective(s)
#68	General	AAS and MAS	• Streamline the connections process

NER S5.2.5.5(c)(1) requires generating systems and IRS to remain in CUO for credible contingency events, but for the purposes of establishing a standard, the defined term 'credible contingency event', by itself, does not set or limit the size of any resulting disturbance that the system must ride through. This is because what constitutes a credible contingency at any point in time can change, including under NER 4.2.3A if AEMO reclassifies a non-credible contingency event as credible where it is considered reasonably possible because of abnormal conditions.

Considering that any type of non-credible contingency event can be declared a credible contingency event at any time, it is impractical to expect a generating system or IRS to ride through all potential credible contingency events. Requiring compliance for reclassified events therefore presents an unmanageable compliance risk.

Reclassification is a useful tool for the operator to manage operational risk because it allows the network to be temporarily operated in a more conservative way in case the reclassified event occurs. This should automatically take into account that the dynamic response of the plant in the vicinity is unchanged, despite the abnormal power system conditions.

Discussion and feedback

This issue was identified as part of the internal AEMO review process, and considered of sufficient value to canvass in this draft report. Noting that there is no operational expectation from AEMO that any plant can or should necessarily ride through a reclassified contingency that is more significant than the most severe 'normally credible' contingency, it seems sensible for NER S5.2.5.5(c)(1) to instead reflect the level and type of contingencies that NSPs will assess to support the maintenance of their network performance requirements.

Options

The options considered to address identified issues were:

1. Do nothing. This means the existing compliance risk will continue.
2. Amend the rule to expand the credible contingency reference by reference to specify credible contingency events selected by the NSP for the purpose of NER S5.1.2.1. This requires the NSP to select the credible contingency events to be used for planning and operation of the transmission and distribution network. It goes on to define what events must, and may, include in its selection (which does not include events reclassified from non-credible to credible).

Recommendation

AEMO recommends Option 2.

3.7 NER S5.2.5.7 – Partial load rejection

3.7.1 Application of minimum generation to energy storage systems

Ref.	Technical Focus Group	Standard type	Objective(s)
#29	General	AAS & MAS	• Streamline the connections process (minor drafting issue)

Description

The following issue was raised by Transgrid in its submission on the approach paper:

"The statement "Minimum generation means the minimum sent out generation for continuous stable operation" should be reviewed to incorporate bi-directional systems. It is understood that ESS will be required to comply with this requirement regardless of whether it is in charging and discharging mode."

The partial load rejection clause was amended as part of the IESS Rule. The amended clause applies generally to IRSs, which could include generating units and loads as well as bi-directional units. Bi-directional units are not likely to have minimum generation for continuous stable operation.

Discussion and feedback

In the prioritisation workshop this issue was rated as medium priority by the majority of participants.

The issue was not further examined at an options assessment workshop.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Amend the clause to refer to generating units for the for the carve out about operating above minimum generation.
3. The issue appears to be a minor one but can be addressed by option 2.

Recommendation

AEMO recommends Option 2.

3.7.2 Clarification of meaning of continuous uninterrupted operation for NER S5.2.5.7

Ref.	Technical Focus Group	Standard type	Objective(s)
#30	General	AAS & MAS	• Align with best power system performance

Description

The AAS requires that a generating system or IRS must be capable of continuous uninterrupted operation during and following a power system load reduction of 30% from its pre-disturbance level or equivalent impact from separation of part of the power system in less than 10 seconds.

AEMO has identified two issues with this clause as currently drafted:

- There is ambiguity in the words "capable of" and whether that means such capability must be enabled at all times.
- The definition of CUO only allows for substantial reductions in output after fault clearance when allowed by specified performance standards (excluding S5.2.5.7), and this clause is otherwise silent on the reduction in active power which would occur as a result of the frequency and inertial response to the loss of load.

Discussion and feedback

The majority of prioritisation workshop participants ranked these issues low, but they can be simply addressed.

AEMO ranked the issue of interpretation of "capability" more highly than other workshop participants.

Options

The options considered to address identified issues were:

1. Do nothing
2. Replace the term "be capable of" with "remain in".
3. Add a statement that for the purpose of this rule, active power may change to oppose a voltage angle change and a frequency change and add a reference to S5.2.5.7 in paragraph (c) of the CUO definition.
4. Amend the continuous uninterrupted operation definition to include reference to active power changes to oppose voltage angle jump and frequency changes.

As this standard reflects a requirement to remain in continuous uninterrupted operation for an abnormal power system condition that could occur at any time, there is a need to have this capability enabled at all times, as reflected in Option 2.

Option 3 allows for:

- Response to oppose an angle jump (seen in GFM inverters and synchronous machines, but possible to program in GFL inverters too)
- Primary frequency response (requirement of all IRS and generating systems, but not part of the technical standards)
- Inertial response (seen in GFM inverters, if programmed and synchronous machines, but not mentioned in the technical standards).

Option 4 is an alternative to Option 3, which makes the amendment in the continuous uninterrupted operation definition. Considering that these responses can occur for other types of disturbances described in S5.2.5.5 as well, AEMO prefers Option 4.

Recommendation

AEMO recommends Options 2 and 4.

3.8 NER S5.2.5.8 – Protection of generating systems from power system disturbances

3.8.1 Emergency over-frequency response

Ref.	Group	Standard type	Objective(s)
#31, #32, #33	General	MAS	• Align with best power system performance • Streamline the connections process

Description

NER S5.2.5.8(a)(2) describes three options for a generating system of 30 MW or more and an IRS (to the extent it comprises bidirectional units) of 5 MW or more to reduce their active power rapidly, in the event of an over-frequency event. The approach paper considered three issues associated with this clause:

1. NER S5.2.5.8(a)(2)(ii) requires the reduction in output to be completed within 3 seconds of the frequency reaching the upper limit of the extreme frequency excursion tolerance limits, but at this level generating systems and IRS are permitted to trip (considering NER S5.2.5.3 and S5.2.5.8(a)(1)), so the response might be too late to be useful.
2. NER S5.2.5.8(a)(2)(i)(B) requires a response that reduces the plant's output by at least half, within 3 seconds, but there are some plant (for example, some hydro generating units) that are physically unable to achieve a reduction output at the required rate safely. The same limitation might also arise with NER S5.2.5.8(a)(2)(ii). The third option, to trip the plant is not desirable as it could reduce the inertia of the power system, which would increase rate of change of frequency.
3. The rule applies different requirements to different size systems based on whether they are bidirectional or not, but there is no sound technical reason for this distinction on size and technology.

NER S5.2.5.8(a)(2) existed before the PFR requirements were introduced in NER chapter 4. A generating system PFR with a 4% droop would reduce its output by approximately half of its maximum power by the time the frequency rose to 51 Hz, if there was no lag in the controls in response to the frequency change (ignoring the 15 mHz PFR deadband).

Discussion and feedback

Participants in the prioritisation workshop ranked these issues medium priority, with issue 1 the highest and issue 3 the lowest of the three. Some participants noted that the introduction of PFR meant that issue 1 was no longer as important. However, AEMO notes that there are still significant numbers of generating systems not currently providing PFR, for which a response under NER S5.2.5.8 is valuable, as a contribution to managing a power system over-frequency event.

The issue was not selected for a follow-up options assessment workshop, as AEMO considers it uncontroversial and relatively straight-forward.

Options

The options considered to address identified issues are:

1. Do nothing

2. Make paragraph (2) apply only if the plant does not provide PFR consistent with the Primary Frequency Response Requirements (published under NER 4.4.2A), considering deadband and droop.
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”.
4. Remove the references in S5.2.5.8(a)(2) to “(not less than the upper limit of the operational frequency tolerance band)”
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.
6. Apply the same size threshold irrespective of size of plant – 30 MW.
7. Apply the same size threshold irrespective of size of plant – 5 MW.

Option 1 is not preferred as it does not address the issue.

Option 2 takes account of the workshop around PFR obviating the need for this clause. Where PFR is effectively providing overfrequency response there is no need for this technical requirement. Note that there may be some variation to PFR requirements, but a variation should reflect the technical capability of the plant for frequency response, and will normally require a lower deadband, and therefore require the plant to commence overfrequency response ahead of a response under this requirement.

Options 3 addresses issue 1 by requiring the response to be completed before the frequency exceeds a level for which generating systems are permitted to trip. Option 4 provides more flexibility for the response to commence at a lower level, which could assist the plant to achieve the response within 3 seconds of reaching 0.5 Hz less than the upper limit of the extreme frequency excursion tolerance limits, considering that this would require an aggressive droop.

Option 5 addresses issue 2.

Options 6 and 7 remove an unnecessary technology specific term. Even though the effect of generation is cumulative, considering that batteries (which fall into the bi-directional category) will generally be captured under the PFR rule in any case, and considering the additional compliance assessment and coordination costs compared with limited benefit, AEMO recommends Option 6 over Option 7.

Recommendation

AEMO recommends Options 2, 3, 4, 5 and 6 as described above.

3.9 NER S5.2.5.10 – Protection to trip plant for unstable operation

3.9.1 Requirements for stability protection on asynchronous generating systems

Ref.	Group	Standard type	Objective(s)
#35	General	AAS, MAS, NAS for asynchronous generating systems	• Clarification of oscillation monitoring and protection

Description

The AAS for NER S5.2.5.10 requires generating systems and IRS to have a protection system to trip the plant for unstable operation. This obligation's objective is to protect the network from active power, reactive power and voltage instabilities caused or amplified by a generating system or IRS. The part of this obligation for asynchronous generating systems was introduced in 2007 when the penetration of renewable generation was minimal and the impact of asynchronous generating systems on the power system negligible.

The AAS for NER S5.2.5.10 specifies different requirements for synchronous and asynchronous production units. For synchronous production units, disconnection is to occur promptly either after the detection of a condition that would lead to pole slipping or in other conditions where a production unit causes active power, reactive power or voltage to become unstable at the connection point. For asynchronous production units, disconnection is to occur promptly when the active power, reactive power or voltage at the connection point becomes unstable, without mention of the plant "causing" the instability. For both types of production units, instability is assessed in accordance with AEMO's Power System Stability Guidelines (PSSG) under NER 4.3.4(h).

The MAS for both synchronous and asynchronous technology states that generating systems must not cause a voltage disturbance due to sustained unstable behaviour of more than the maximum level specified in Table 7 of AS/NZS 61000.3.7:2001 as shown in Figure 4. Importantly, limits specified in Table 7 of AS/NZS 61000.3.7:2001 do not reflect suitable settings for a protection system.

r (hour^{-1})	$\Delta U_{dyn}/U_N$ (%)	
	MV	HV
r ≤ 1	4	3
1 < r ≤ 10	3	2.5
10 < r ≤ 100	2	1.5
100 < r ≤ 1000	1.25	1

Figure 4 Emission limits for voltage changes in function of the number of changes per hour (Table 7 of AS/NZS 61000.3.7:2001)

In recent years, the current formulation of the AAS and MAS has caused significant interpretation and application uncertainty, causing delays and potentially suboptimal outcomes in multiple connection projects for asynchronous generating systems. For example, there are concerns over whether asynchronous generating systems should be disconnected without considering their contribution to the instability, whether a prompt disconnection is the best solution for a modern grid with high renewable generation penetration, and what types of instabilities should be covered under NER S5.2.5.10.

Equally important, in the recent years, the NEM power system has experienced a number of oscillatory events in multiple states (including Victoria[34], South Australia and Queensland) with different levels of oscillation severity. Currently, all of these events require individual investigation from NSPs and AEMO to identify contributing generating systems and IRS, and some have required manual interventions to disconnect plant which cause or

[34] https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-oscillations

contribute to instability due to the absence of protection required under the AAS of NER S5.2.5.10. This cannot be considered a sustainable solution in a power system with a large and steadily increasing number of asynchronous generating systems and IRS. Thus, a clear and meaningful formulation of NER S5.2.5.10 that can be readily applied to present and future NEM power system conditions is a necessary step in preparing the network for further transition towards renewable generation.

Discussion and feedback

In prioritisation and options assessment workshops, participants indicated a high level of support in principle for addressing this issue. Several issues were raised by workshop attendees and this feedback aligns with AEMO's observation that issues around NER S5.2.5.10 have caused multiple connection projects to experience delays.

AEMO has identified seven issues relating to NER S5.2.5.10 and these are discussed below.

Issue 1:

NER S5.2.5.10(a)(2) requires asynchronous generating systems to 'promptly' disconnect for conditions where active power, reactive power or voltage become unstable. However, if multiple generating systems or IRS participate in the same oscillations, the prompt disconnection of all of them may pose a risk to power system security when potentially hundreds of megawatts of generation are affected.

To address issue 1:

- The AAS would require a protection system that has the capability to detect an instability and disconnect the generating unit based on its settings such as disconnection time and oscillation magnitude. The protection system settings would not be recorded in the GPS but would be nominated and reviewed by the NSP and AEMO, as required, with the capability of the protection system to disconnect the generating unit only being enabled with the agreement of the NSP and AEMO.
- The MAS would be the same as the AAS for generating system greater than a threshold of 20 MW but would allow an exemption to not require a protection for generating systems below this threshold. This reduce requirement for smaller generating systems would lower their costs, noting that all generating systems above a 5 MW threshold would still be required to provide monitoring and remote disconnection capability, as discussed under issues 6 and 5 respectively.

This approach would support the management of instabilities by only disconnecting generation and IRS in a coordinated manner, while aiming to avoid unnecessary disconnection, and allow the settings to be amended as the power system conditions change without the need to renegotiate the GPS.

AEMO seeks stakeholder views on the appropriateness of an exemption and level of the 20 MW threshold proposed for the MAS.

Issue 2:

NER S5.2.5.10(a)(2) explicitly requires a protection system to disconnect the generating units for an instability, whereas a better overall outcome may be achieved by other actions such as:

- ramping down the active power of one or many production units participating in the observed instability; or
- dynamically changing the control mode of the generating system.

These actions can be tried ahead of disconnection in an attempt to minimise the impact on the operation of the power system because the power system can usually be operated indefinitely with a voltage, reactive power or active power instability, unless the oscillations are large.

To address issues 2:

- The AAS would allow, but not necessarily require, for other actions ahead of disconnection of the generating unit, and then only disconnecting the generating system if the instability persists. The functionality, and later the settings, would need to be agreed with AEMO and the NSP.
- The MAS would not require other actions ahead of disconnection.

This would increase generators and IRPs, AEMO and the NSPs' flexibility to manage instabilities and would be likely to reduce unnecessary generating system disconnection. It would also not require additional functionality if the cost and the complexity was not warranted.

Issue 3:

For both the AAS and MAS, NER S5.2.5.10 defines an instability with reference to the PSSG.[35] However, currently the PSSG focuses on system operations and provides no detailed guidance on the assessment for generator performance standards. Perhaps more importantly, the PSSG lists multiple types of instabilities (e.g. transient, oscillatory, small signal etc.) but it is not clear which types of instabilities are relevant to NER S5.2.5.10.

To address issues 3:

- The NER S5.2.5.10 could be amended to specify a minimum set of types of instability to be included in the AAS and MAS. This would ensure that NER S5.2.5.10 identifies the types of instabilities that the generating unit or IRS should protected against.

Alternatively, AEMO could amend the PSSG to clarify the types of instability that are relevant to S5.2.5.10 at any time using its power under NER 4.3.4(h), without a rule change. This alternative is included in Option 3 below.

Issue 4:

Currently the AAS in NER S5.2.5.10(a)(1) for synchronous generating units specifically requires a unit to be disconnected when conditions that would lead to pole slipping are detected or when the unit is causing active power, reactive power or voltage at the connection point to become unstable. However, the equivalent requirement for asynchronous systems requires asynchronous production units to be disconnected for the presence of active power, reactive power or voltage instability at the connection point, regardless of whether the plant is contributing to the disturbance. This requirement, as written, does not align with the needs of the power system. Promptly disconnecting a generating system that is actively damping the oscillation or one that is not responding to the oscillation would be detrimental.

There was broad agreement at the options assessment workshop that the protection systems should only disconnect those production units that are causing or exacerbating the instability. This would both minimise the potential risk to power system security and provide more certainty to the generators or IRP that their plant will not have to disconnect unnecessarily.

[35] https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/power-system-stability-guidelines.pdf?la=en

AEMO has consulted with a number of OEMs to ascertain whether their plant protection systems can determine if a production unit is contributing or not to an instability. Several of the OEMs indicated that the first versions of their protection systems are already available or will be available later in 2023. However, while multiple OEMs appear to be well advanced, they still need to establish their effectiveness to determine which individual generating systems are contributing to an instability that involves multiple generating systems or IRS. Also, as the cost of these protection systems may be non-trivial, AEMO proposes that the requirement to include this type of protection is likely to be justified for larger generating systems or IRS.

In addition, experience from an overseas network operator[36][37] indicates that generator contributions to an instability may also be estimated by a centralised system based on phasor measurement units (PMU) data provided by generators from their connection points. While it is too early to determine the need for such a system, AEMO considers that the NER should not preclude centralised systems in the future that determine generating unit disconnections or other corrective actions under NER S5.2.5.10.

To address issue 4:

- The MAS would not require the capability to detect if a generating system or IRS is contributing to an oscillation detected at its connection point.
- The AAS for a generating system or IRS to require its units or system to include either:
  1. A detection device that has the capability identify whether the unit or system is contributing to an instability or sustained oscillatory response in active power, reactive power or voltage is detected; or
  2. Subject to the agreement of the NSP and AEMO, a PMU connected to the unit or system that is capable of providing information from the PMU to a centralised system, and receive signals from the centralised system, to identify whether the unit or system is contributing to an instability or sustained oscillatory response.

This would allow for both a local and a centralised system to detect which plants are contributing to the instability and then to disconnect them in a coordinated manner to manage the instability. This approach provides AEMO and the NSP with visibility of which plants are contributing to the instability, both for event analysis and potentially for real-time operations. AEMO expects that the inclusion of a requirement to detect if the plant is contributing to an instability will encourage OEMs to further enhance and improve their protection systems.

Issue 5:

The AAS requires the generating unit to disconnect when an instability occurs, while the MAS prohibits the generating unit from creating a sustained instability larger than the level specified in table 7 of AS/NZS 61000.3.7:2001. That is, the MAS has the effect of allowing small oscillations, provided the power quality standards are met. The intent of the current MAS formulation is to exclude small systems, where the impact of instability is small, from the requirement for a protection system to disconnect for unstable operation. However, while a small plant might be able to meet the current MAS requirement, a large plant may not, if the resulting instability can be too large to meet the level in table 7 of AS/NZS 61000.3.7:2001. Therefore, the MAS can be more arduous than the AAS for a larger plant under some circumstances.

[36] https://www.naspi.org/sites/default/files/2020-07/Online%20Oscillations%20Analysis%20at%20ISO%20New%20England.pdf

[37] S. Maslennikov and E. Litvinov, "ISO New England Experience in Locating the Source of Oscillations Online," in IEEE Transactions on Power Systems, vol. 36, no. 1, pp. 495-503, Jan. 2021, doi: 10.1109/TPWRS.2020.3006625
URL: https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=9132669&isnumber=9316338

To address issues 5, the MAS could be amended to:

- Remove the reference to AS/NZS 61000.3.7 from the MAS.
- Define instability with reference to the PSSG.
- Require the capability for the plant to be remotely disconnected by the NSP or AEMO.

These amendments to the MAS would ensure that the MAS is always less arduous than the AAS, which would remove the potential confusion from the negotiation process for NER S5.2.5.10.

In addition, the proposed amendments would give the NSP and AEMO the capability to disconnect the plant remotely if required, based on monitoring discussed under issue 6.

Issue 6:

As discussed in issue 5, the current MAS formulation does not specify disconnection and this raises the question of whether the objective of this standard should be about just monitoring for instability, or whether protection is also required. AEMO considers that there are benefits to system security in retaining the requirement for monitoring in the MAS by collecting data for off-line network analysis from protection relays directly or from dedicated devices such as PMUs. This would provide further insight into the management of instabilities that can affect large parts of a network with a high penetration of asynchronous generation.

To address issue 6:

- The AAS would require a production unit or system to have a PMU. The PMU would need to monitor and analyse the active power, reactive power and voltage at the plant, and provide the results to AEMO and the NSP.
- The MAS would require a production unit or system to have a device that monitors the active power, reactive power and voltage at the plant, and is capable of providing timestamped data to the NSP, and AEMO if required.

This would ensure that unstable behaviour at a generating system or IRS connection point is visible to AEMO and the NSP, if required for off-line analysis or in real time operation decisions.

Issue 7:

It is common practice in critical protection system to include duplication of the protection relays and other key elements of the protection system.

AEMO considers that duplication of the instability detection devices under S5.2.5.10 is not required as removing unstable plant is generally only required after tens of seconds or even minutes. Pole slip protection may be duplicated, as pole-slipping can induce high voltages on the rotor, which might cause damage to the plant.

Options

To address the discussed issues with the NER S5.2.5.10, the options considered were:

1. Do nothing.
2. To adopt all seven proposals to address the seven issues identified, including amending NER S5.2.5.10 to specify additional clarity for the PSSG under issue 3.

3. Option 2 excluding proposal 3, with AEMO using its existing power under NER 4.3.4(h) to review the PSSG to address the issues raised by stakeholders.

Option 1 is not preferred as it does not address the issues raised by stakeholders.

Option 2 addresses all the issues addressed raised by stakeholders. The reasons for recommending each of the seven proposals is discussed above. This would allow AEMO and the NSPs to have visibility of unstable operation of generating systems and to implement approaches to manage them. It would also clarify the obligations on generators and IRS.

Option 3 is preferred as it also addresses the issues raised by stakeholders, with AEMO reviewing the PSSG independently of any rule change as this would allow AEMO more flexibility.

Recommendation

AEMO recommends NER amendments to give effect to Option 3.

In the AAS, specify that a generating system or IRS, for its asynchronous units:

- must have a protection system that can detect an instability and disconnect the production unit based on its nominated settings such as disconnection time and oscillation magnitude.
- may take corrective actions such as ramping down or changing control mode (where the thresholds and corrective actions, are to be coordinated by the NSP).
- The generating system or IRS must have a detection device to identify whether the production unit or system is contributing to the instability or (subject to the agreement of the NSP and AEMO), a PMU connected to the unit or system capable of providing information to a central system to identify if the unit or system is contributing to an instability. Where a central system is used, the generating system or IRS must have the capability to accept information on contribution from the central system.
- The generating system or IRS must have a PMU, regardless of whether a centralised system for determining contribution to an oscillation is used. The PMU would need to monitor and analyse the active power, reactive power and voltage at the plant, and provide the results to AEMO and the NSP.

The MAS, for a generating system or IRS of would require:

- for generating systems or IRS greater than 20 MW, its asynchronous units,a protection system to disconnect for instability or sustained oscillatory response in active power, reactive power or voltage.
- for its synchronous units, to have a protection system to disconnect a synchronous generating unit for pole slipping.
- have capability to accept a trip command from AEMO or the NSP.

In the MAS:

- require a monitoring system for active power, reactive power and voltage, capable of providing timestamped data to the NSP and AEMO.
- not require a detection device to identify whether the production unit or system is contributing to the instability.
- remove reference to AS/NZS 61000.3.7:2001 from the MAS.

AEMO would welcome feedback on the threshold proposed under issue 1 above.

3.10 NER S5.2.5.13 – Voltage and reactive power control

3.10.1 Voltage control at unit level and slow setpoint change

Ref.	Group	Standard type	Objective(s)
#38	General & GFM	AAS and MAS	• Align with best power system performance • Remove impediments for GFM inverters

Description

Voltage control at unit level

Voltage control at unit level is a long-established control strategy for synchronous machines, where the unit controls its terminal voltage. For synchronous machines with a step-up transformer to the connection point voltage level, a fast voltage response at the terminal provides a voltage droop response at the connection point, with reactive power from the generator changed either by setpoint change at terminal level or tap change.

For asynchronous plant, the voltage control has typically been implemented through a power plant controller (PPC) which provides active and reactive power commands to the units. The PPC controls the connection point voltage or some other location nominated in the GPS, usually with voltage droop control.

This type of control tends to be less stable than unit-level voltage control for low system strength conditions because of the cycle time of the PPC and the variable communications delays between the PPC and production units. Responses that are not adequately damped have been observed during testing on some generating systems because of communications delays.

This type of control is also inherently reliant on the quality of communications between the PPC and the production units. This makes it less resilient to communications failures. Over time, there have been incidents where communications failures have led to instability of the controls, which could lead to impacts on power system security or quality of supply (particularly flicker).

For GFM inverters where there is an expectation of operation at very low short circuit ratio, unit level voltage control is likely to be particularly beneficial, for all the reasons described above.

Unit level voltage control can also provide benefits for voltage management under fault conditions, eliminates instability issues associated with transition between PPC and inverter voltage control during fault conditions, and is likely to reduce over-voltages following fault clearance since there is no delay time associated with a hand-over between controllers.

As a general principle, the NER access standard should avoid impediments to voltage control (and other modes) at the unit level for both synchronous and asynchronous plant. The present wording implies system-level control, although some clauses confuse unit and system control. The main cause of impediments in the current NER wording is the requirement for setpoint steps in voltage, power factor and reactive power mode, where the generating system (or IRS) must demonstrate settling time and, for voltage control, reactive power rise time. Note that these requirements tend to be less of a problem for large synchronous plants, where their generating unit has its own registered performance standards and is effectively treated as a generating system.

Slow setpoint change

At present, NER S5.2.5.13 requires the generating system or IRS to establish performance requirements for settling time for active power reactive power and voltage due to a step change of voltage setpoint or voltage at the location agreed under clause subparagraph (2B)(i) and (for asynchronous generation) a risetime for a 5% step change in voltage setpoint. The AAS requires settling time of 5 seconds (7.5 s into a limiter) and 2 seconds rise time.

In normal operation, there is no need for fast setpoint changes. In many synchronous machines there is a rate limiter on the setpoint control to avoid inadvertent fast setpoint changes which can cause a disturbance to the power system's operation.

Fast voltage control at the unit level can help to stabilise voltages, but to avoid interaction between the PPC and inverter controls, slow setpoint control would be desirable in conjunction with the fast inverter voltage control. It is noted that current NER technical requirements do not specifically allow for this arrangement.

Discussion and feedback

Most prioritisation workshop participants ranked these issues as high or medium priority. AEMO undertook a further options assessment workshop on these issues.

Most participants recognised the merits of unit level voltage control. However, some expressed concern about how one would test the controller performance without a 5% setpoint step change, since it is difficult to achieve such voltage step on the power system for testing purposes.

Options

The options considered to address identified issues were:

1. Do nothing.
2. Amend NER S5.2.5.13 to clarify that voltage, reactive and power factor control may be implemented at production unit level, for both synchronous and asynchronous plant.
3. Specifically allow rate-limited setpoint change of the generating system, for operational purposes. For assessment of the stability of the system (risetime and settling times), setpoint changes with ramp limiters disabled should be used.

Option 1 is not preferred as it does not address the existing issues.

Option 2 has advantages, as articulated above, including improved stability for low system strength and improved resilience to communications failure.

Option 3 is consistent with Option 2, and with commissioning and compliance assessment processes.

Option 3 is consistent with good industry practice previously applied to synchronous machines, but also assisting operation of the power system by preventing inadvertent voltage disturbances caused by fast setpoint steps on asynchronous generating systems. Allowing this control arrangement better aligns with the needs of power system operation and is also, conceptually, a better control strategy for GFM inverters with voltage control at the production unit level, than a control strategy where PPC and unit level controls are both fast and could adversely interact. The same control strategy for GFL inverters would be beneficial, especially in high system impedance (low fault level) conditions.

Recommendation

AEMO recommends NER amendments to give effect to Options 2 and 3 as described above and to apply the changes to both synchronous and asynchronous plant.

The slow setpoint change amendment would apply to voltage, power factor and reactive power modes.

3.10.2 Realignment of performance requirements to optimise power system performance over expected fault level (system impedance) range – Voltage control

Ref.	Group	Standard type	Objective(s)
#39	General	AAS, MAS and NAS	• Align with best system performance

Description

NER S5.2.5.13 requires for voltage control in the AAS for asynchronous plant a rise time of 2s for a 5% setpoint step change, and 5s settling time for 5% setpoint or power system voltage change. Similar requirements for settling time exist for the MAS and also for synchronous machines. The MAS settling times are longer than those in the AAS.

Settling time is used as a measure of stability in this clause, but a long settling time can also arise from an over-damped response, which would also be associated with a long rise time.

Rise time is used as a measure of speed of response. The intent of this standard is to require fast and stable response.

When these requirements were introduced, synchronous machines were the dominant technology in the NEM, and fault level was increasing with the size of the power system. Since then, the number of IBR on the power system has increased substantially. Moreover, as synchronous generators retire, there is a trend towards declining fault levels and increasing system impedance[38].

Experience of the past few years has shown that some control interactions - especially, but not exclusively, associated with GFL inverters - are sensitive to system impedance level. As system impedance increases, the controls can become less stable. Synchronous machines and GFM controls also show a tendency to less stable operation for high system impedance, although to a lesser extent.

Stability is more affected at very high impedance conditions, which are more likely to occur when the power system is under stress from generation and transmission outages. While these conditions occur infrequently, it is important that stability of the power system is maintained, to reduce the risk of cascading failures and loss of supply.

A further consequence of the current energy transition towards fewer synchronous machines and more IBR is that at present, and in the short to medium term, parts of the power system will experience dispatch scenarios that lead to a wide range of system impedances – low to high.

Tuning of control systems usually considers a range of dispatch and single network outage conditions. Tuning for a wide range of system impedances (reflecting different dispatch and network outage conditions) can be challenging as the rise time and settling times can be quite different at low and high system impedances:

[38] Reference to system impedance is more relevant than fault level or short circuit ratio in this context, as the clause deals mainly with voltages in the normal operating range, rather than fault conditions.

- At low system impedance – slower, but stable (longer rise time and settling time, if over-damped).
- At high system impedance – faster, but less stable (shorter rise time and settling time, unless highly under-damped).

If the controls are set to meet the AAS for rise time and settling time for low system impedance conditions, then the response may be unnecessarily oscillatory for high system impedance conditions and more likely to be unstable for multiple contingency events.

AEMO proposes that the power system is best served if generators prioritise stability over speed of response, where there is a conflict between them. For the AAS this can be achieved if the tuning prioritises the rise time and settling time for the highest system impedance condition.

Discussion and feedback

Participants at the prioritisation workshop generally ranked this issue highly. In the options assessment workshop participants strongly agreed that stability should be prioritised over speed of response where there is a conflict between them. Some participants argued for use of system impedance rather than fault level, which AEMO has attempted to capture in the issue description above.

One participant noted that fast response is necessary for preventing voltage collapse. AEMO also notes that fast response within a few milliseconds opposing a voltage change or voltage angle change, is required for a production unit to contribute to system strength.

Options

1. Do nothing
2. Require that the NSP must specify the range of system impedances for which the plant is to be tuned.
3. Require that the range of system impedances for which the plant is tuned be recorded in the RUG.
4. Require that the range of system impedances for which the plant is tuned be recorded in registered GPS.
5. In the AAS:
   - Require a 2 second rise time of reactive power for a 5% setpoint change for the highest system impedance level nominated by the NSP
   - Retain a 5 second settling time (5% step not into a limit) and 7.5 s settling time (5% step into a limit).

   In the general requirements:

   - Where 5 second settling time cannot be met at both minimum and maximum system impedance, control tuning should target AAS level settling time for maximum system impedance and as close to AAS level settling time as possible for highest system impedance; and settling time for low and high system impedances to be recorded in the GPS.

   In the MAS:

   - Settling times to be retained as per existing MAS for highest system impedance level and recorded in the GPS for lowest system impedance level.
6. In the AAS:

- Require a 2 second rise time of reactive power for a 5% setpoint change for the highest system impedance level and a typical system impedance level nominated by the NSP.
- Retain a 5 second settling time (5% step not into a limit) and 7.5 s settling time (5% step into a limit) for highest system impedance and a typical system impedance nominated by the NSP.
- The typical system impedance level should be reflective of typical dispatch levels.
- Settling time for highest, typical and lowest system impedances to be recorded in the GPS.

In the MAS:

- Retain settling times as per existing MAS for highest system impedance level and recorded in the GPS for highest system impedance level and a typical system impedance nominated by the NSP.

  The typical system impedance level should be reflective of typical dispatch levels.

7. In the AAS:

- Require a 2 second rise time of reactive power for a 5% setpoint change for the highest system impedance level nominated by the NSP.

In the general requirements:

- Where 5 second settling time cannot be met at both minimum and maximum system impedance, control tuning should be set to achieve AAS level settling time for maximum system impedance and target as close to AAS level settling time as possible for highest system impedance, and settling time for low, typical and high system impedances to be recorded in the GPS.

  The typical system impedance level should be reflective of typical dispatch levels.

In the MAS:

- Retain settling times as per existing MAS for highest system impedance level and
- Allow a higher settling time for lowest system impedance level, provided the response is critically- or over-damped.
- Where the MAS settling time cannot be met at both highest and lowest system impedance settling times for highest, typical and lowest impedances are to be recorded in the GPS.

These options should be considered in conjunction with the issues and options described in section 0 of this report.

The “Do nothing” Option 1 does not address the issue and is not preferred. This is because the range between automatic and minimum does provide a reasonable range for negotiation. In addition, the AAS is typically not achieved for many plants, especially regarding the 2 second risetime, and achieving it does not necessarily improve power system performance.

Options 2, 3 and 4 involve the NSP nominating a range of system impedances, and how these should be recorded. The NSP is in the best position to advise the range of system impedances for which the plant ought to be tuned, considering dispatch patterns and network outage impacts. This information improves clarity for tuning and assessment and, if recorded in a reference document, it will facilitate future coordination of settings changes if required to improve power system performance in situations where the range of system impedances may change substantially. Possible places to record this information would be the GPS or the RUG. Either would make the tuning range visible and facilitate coordination of future settings changes. If located in the GPS, updates of that document would be required, possibly using NER 4.14 to alter the GPS.

Options 5 and 6 vary the automatic access standard. Both seek to focus the performance requirements on the higher end of system impedances (lower fault levels). Option 5 establishes a rise time for the highest system impedance, but has the expectation of the AAS settling time requirement being met for both high and low system impedances. AEMO's experience is that the settling time requirement can typically be met for voltage and reactive power unless the range of system impedances is large.

Option 6 introduces a third system impedance level. The advantage is that there should be a point of comparison for assessment against commissioning tests. The disadvantage is that it would require more simulations to establish the three points to go in a registered GPS.

Option 7 combines elements of 5 and 6, only requiring a settling time for typical system impedance to be recorded where the 5 second settling time cannot be achieved for the full range of impedances. It only requires a typical level to be recorded where there are different levels of settling time for highest and lowest system impedance conditions. It also relaxes the settling time for low system impedance in the MAS, but only if the low system impedance response is over-damped or critically damped (i.e. not oscillatory).

Recommendation

AEMO recommends NER amendments to give effect to Option 3 and Option 7.

3.10.3 Materiality threshold on settling time error band and voltage settling time for reactive power and power factor setpoints

Ref.	Group	Standard type	Objective(s)
#40 & # 41	General	AAS & MAS	• Streamline the connections process

Description

NER S5.2.5.13 requires calculation of settling time for each of voltage, reactive power and active power for steps of voltage, reactive power and power factors for operation in those modes.

This section describes two issues related to these calculations:

- No materiality threshold on settling time error bands.
- Requirement for settling time to be calculated for variables not controlled by the stepped quantity.

In this report, AEMO has combined both issues, as they also have some overlap.

No materiality threshold on settling time error band

Settling time is defined in the NER as:

> 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, the maximum change induced in that output quantity; or

(b) the sustained change induced in that output quantity.

The settling time is dependent on the response staying within a band of values, (the error band), defined relative to the change in the measurement. For a small transient the error band becomes so small that the calculation of settling time becomes meaningless.

For example, if the transient in active power for a 5% voltage step is 2 MW, the error band is +/- 0.2 MW.

This level of variation in active power is not material in the context of the NEM, and the calculation could be omitted without any risk to power system security.

The error band is in the order expected for noise, especially when it is applied to measurements on the power system for compliance assessment.

The measurement of settling time could therefore have a materiality threshold below which the settling time is deemed to be satisfactory.

Requirement to calculate settling time for quantities not controlled by the stepped quantity

A similar issue is that NER S5.2.5.13 currently requires compliance with settling time requirements on quantities that are not controlled by the step. This is particularly evident in compliance testing for this standard for electrically noisy locations on the power system.

Examples are:

- Requirement for voltage settling time for reactive power step in reactive power control. The reactive power step cannot damp any oscillations or variations in voltage that originate from the power system, as there is no feedback from voltage.
- Requirement for voltage settling time for a power factor step. The reactive power change is only a function of the active power, and there is no feedback from voltage, so the control cannot damp any oscillations or variations in voltage that originate from the power system.

In both cases, the impact the reactive power change only reflects onto the power system voltage, but does not control it, so calculation of voltage settling time as a measure of the generating system's stability is not meaningful.

Discussion and feedback

These issues were not rated as high priority at the prioritisation workshop because they are not as important as some other issues under review. Some engineers who work in this space make allowances for the materiality of the settling time by not requiring it to be calculated for very small deviations. Others instead only require the assessment of settling time for the controlled variable. Either way, however, there is no consistent application across the NEM.

Where a pragmatic interpretation approach is not taken and settling times calculate to large values, even though this is mostly resulting from noise, this can prolong negotiation times unnecessarily. Likewise, for compliance testing, NER requirements for calculating settling time would seem to be not consistent with engineering considerations of materiality and appropriateness, which in turn can lead to, in some cases, undue delay.

Options

1. Do nothing.

2. Remove the requirement for assessing settling time for voltage for reactive power and power factor steps.
3. Apply materiality thresholds to active power for voltage steps in voltage control, power factor control and reactive power control.
4. Remove requirements for assessing active power settling time for voltage, reactive power or power factor steps.

Option 1 does not address the issues.

Option 2 addresses the issue for voltage response to reactive and power factor controls above. This option is beneficial because calculation does not provide additional useful information that could not be determined from reactive power settling time calculation, and can be misleading as the voltage is not controlled, and can be affected by external sources. This option therefore improves the efficiency of the connection and compliance assessment processes.

Option 3 addresses the issue of very small error bands for active power when the active power response is small. It would save unnecessary effort during the connection process in negotiating around insignificant or immaterial results.

Option 4 omits the active power settling time calculation for all three modes.

There can be interactions between active power and reactive power controls on some plant. For example, inverters are typically operated in reactive power priority, which prioritises the production of reactive power over active power. On solar photovoltaic inverter systems, a step change in reactive power and the resultant voltage change, that causes the AC peak inverter voltage to exceed the DC voltage, will result in a DC controller action to increase the DC voltage, which reduces active power output. Therefore, a step change to voltage or reactive power could lead to an active power control action with an oscillatory response. AEMO therefore considers that a materiality threshold on the active power settling time calculation would be more appropriate than omitting the settling time requirement altogether.

AEMO proposes that a suitable active power threshold could be 5 MW, which would result in an error band of ±0.5 MW. This amendment would also mean that active power settling time compliance assessment would not be required for well-behaving small plants. Small plants are unlikely to cause stability problems for the power system even in the event of an active power instability from a voltage or reactive power step, and in any case there is a requirement for active power control systems to be adequately damped under S5.2.5.14.

Recommendation

AEMO recommends NER amendments to give effect to Options 2 and 3.

3.10.4 Clarification of when multiple modes of operation are required

Ref.	Group	Standard type	Objective(s)
#42	General	AAS	• Streamline the connections process

Description

NER S5.2.5.13 has an AAS requirement for generating systems and IRS to:

- operate in multiple modes (voltage control, reactive and power factor);

- switch between modes; and
- be able to do so through remote control in response to a command from AEMO.

In practice, most plant will operate in one mode over its life. There are some exceptions to this that are site-specific. For example, there may be network outage conditions for which a change of mode is necessary to manage a network condition specific to the outage where the plant might otherwise need to be disconnected. Reactive power mode is sometimes used in testing to demonstrate reactive power range. It may also be used in coordination of testing with nearby generating systems, to reduce the controller interactions between plants for testing purposes. In rare circumstances, a mode that restricts reactive power output might be useful to have as an emergency operating mode. Emergency change of modes cannot be used if the mode has not been commissioned prior to the event.

Requiring operation in three modes requires all the activities of connection and compliance to be repeated for multiple modes, i.e.:

- tuning controllers,
- undertaking studies and reporting them,
- review by the NSP and AEMO,
- repeating the studies and reports later with as-built models,
- commissioning the controls, testing compliance and review results by AEMO and the NSP
- on-going compliance testing.

The above steps involve a non-trivial amount of cost and effort over the life of a plant.

Streamlining the relevant requirements, so that they provide benefits of multiple modes while not generating unnecessary work, would improve efficiency of generating system and IRS connections.

The primary mode of operation is usually voltage control, which usually provides best outcomes for controlling voltage on the power system. Historically, some DNSPs requested power factor control, but this is now uncommon. For a secondary mode, reactive power mode may be used, typically with a restricted reactive power range. Operation in reactive power mode with full reactive power range (outside of controlled test conditions) could lead to undesirably high or low voltages on the power system.

Discussion and feedback

In the prioritisation workshop, most participants agreed that the current rule is not efficient. Some participants commented on the occasional situation in which network conditions require a second mode. AEMO has included those broader considerations in its description of the issue.

AEMO ran an options assessment workshop on this issue. Most participants broadly agreed with reducing the required modes to two with a primary and secondary mode. Some participants agreed that the secondary mode could or should have a reduced range. Others suggested that relaxing performance requirements for the secondary mode might be simpler than limiting the range.

Most participants agreed that voltage control should be the primary mode in most or all cases. Some participants noted that some DNSPs still required power factor mode.

Options

1. Do nothing
2. Require two modes in the AAS (where the "primary mode" is the mode the plant is expected to operate in most of the time):
   - with the ability to switch between them
   - where primary mode is voltage control
   - where secondary mode is either power factor or reactive power
   - with reduced assessment requirements for secondary mode.
3. Require two modes in the AAS where need for an additional mode is demonstrated by the NSP or where the primary mode is power factor control – where:
   - If a secondary mode is required, provide ability to switch between them
   - If the primary mode is power factor, the secondary mode must be voltage control
   - If the primary mode is voltage, reduce the assessment requirements for the secondary mode.

Some workshop participants commented that only voltage control is required and that power factor or reactive power control could be implemented through a slow outer loop control. However, AEMO notes that this might not always work for unusual network conditions, where restricted operation is necessary. Another workshop participant commented that the current rule requires "capability" to have multiple modes, and that there should not be a requirement to demonstrate compliance with three modes. AEMO notes that having capability for three modes without tuning or commissioning them means that they cannot be used without further work.

Option 1 does not address the issue. Workshop participants agreed that there were efficiencies to be gained from modifying the AAS.

Options 2 and 3 put more emphasis on voltage control, with reduced requirements for the secondary mode, where the primary mode is voltage control. Both options can generally be expected to reduce the effort and cost required compared with the current arrangements, with negligible loss of functionality.

Option 3 requires justification from the NSP that a secondary mode is required. It also allows for the primary mode to be power factor control. AEMO considers that there is sufficient use of a secondary mode to justify having tuning established for it. AEMO also considers that in most circumstances the primary mode should be voltage control. At the options assessment workshop some DNSP representatives commented that they used to ask for power factor control, but no longer take that approach. If the NSP requires power factor control that can still be achieved as a negotiated access standard.

Secondary mode requirements relaxation in the AAS

Considering the reduction in secondary mode requirements for power factor or reactive power control, the requirements that add least value are the requirements for setpoint step tests, with specified settling times, which could be omitted. The key requirement for these modes is to be stable for voltage disturbances on the power system. The settling time for response to voltage steps on the power system should therefore be retained as requirements for power factor and reactive power modes.

Recommendation

AEMO recommends NER amendments to give effect to Option 2.

3.10.5 Impact of a generating system on power system oscillation modes

Ref.	Group	Standard type	Objective(s)
#43	General	AAS and MAS	• Align with power system performance

Description

The AAS for NER S5.2.5.13 requires:

> a *generating system* or *integrated resource system* must have plant capabilities and control systems sufficient to ensure that:
>
> (i) power system oscillations, for the frequencies of oscillation of the *production unit* against any other *production unit*, are *adequately damped*;
>
> (ii) operation of the *generating system* or IRS does not degrade the damping of any critical mode of oscillation of the *power system*; and
>
> (iii) operation of the *generating system* or IRS does not cause instability (including hunting of tap-changing transformer control systems) that would adversely impact other *Registered Participants*;

The AAS also requires a power system stabiliser.

The equivalent MAS requires:

> a *generating system* or *integrated resource system* must have *plant* capabilities and *control systems*, including, if appropriate, a *power system* stabilizer, sufficient to ensure that:
>
> (i) *power system* oscillations, for the frequencies of oscillation of the *generating unit* against any other *generating unit*, are *adequately damped*;
>
> (ii) operation of the *generating unit* does not degrade:
>
> (A) any mode of oscillation that is within 0.3 nepers per second of being unstable, by more than 0.01 nepers per second; and
>
> (B) any other mode of oscillation to within 0.29 nepers per second of being unstable; and
>
> (iii) operation of the *generating unit* does not cause instability (including hunting of *tap-changing transformer control systems*) that would adversely impact other *Registered Participants*;

These requirements were originally written around synchronous machines, especially relating to electro-mechanical interarea mode oscillations.

Both the AAS and MAS rely on the definition of the term *adequately damped* as follows:

> In relation to a *control system*, when tested with a step change of a feedback input or corresponding reference, or otherwise observed, any oscillatory response at a *frequency* of:
>
> (a) 0.05 Hz or less, has a damping ratio of at least 0.4;
>
> (b) between 0.05 Hz and 0.6 Hz, has a halving time of 5 seconds or less (equivalent to a damping coefficient –0.14 nepers per second or less); and

(c) 0.6 Hz or more, has a damping ratio of at least 0.05 in relation to a minimum access standard and a damping ratio of at least 0.1 otherwise.

$$y(t) = A\,e^{-\lambda t}\cos(\omega t - \phi)$$

$$\text{damping ratio } \zeta = \lambda / \sqrt{\omega^2 + \lambda^2}$$

$$where$$

$$A = magnitude$$

$$\lambda = decay\ rate$$

$$\omega = angular\ frequency$$

$$\Phi = phase\ angle$$

$$\text{Halving time} = \ln(2)/\lambda$$

The equations in the box above show the relationship between the damping ratio and other quantities associated with the oscillation.

In recent years, the power system has exhibited an increasing incidence of oscillations at sub-synchronous frequencies that are sensitive to system strength and are typically associated with control interactions between GFL inverters or between GFL inverters and other electronic devices on the power system.

The frequencies have typically been observed, so far, in the range 7 Hz and up to about 20 Hz.

Considering the equations above, for a 10 Hz oscillation, a halving time of 0.11 s and damping ratio of 0.1 corresponds to a decay rate of 7.

In the power system, oscillations have been observed for seconds or tens of seconds at a time, compared with a halving time of around 0.11 s. In Australia, most of the observed oscillations to date have been small, but overseas there have been reported incidences with larger magnitude oscillations. There appears to be a mismatch between the requirements for generating system responses to be adequately damped and what has been observed on the power system.

In the case of the 7-10 Hz oscillations, improved damping has been achieved by:

- retuning existing GFL plant or
- introducing synchronous condensers

Simulations suggest that GFM inverters would, similar to synchronous condensers, also serve to damp types of oscillations that are sensitive to system strength.

It seems clear that, for oscillations that are sensitive to system strength:

- oscillations are likely to become worse over time as more synchronous generators are displaced by GFL inverters.
- there are control strategies that can improve the performance of GFL inverters to make them behave in a way that resists a change in voltage magnitude or angle (i.e. stiffens the voltage) to some extent.

- GFM inverters and synchronous condensers should improve those types of oscillations that are sensitive to system strength because by their nature they are voltage sources, and naturally respond in a way that stiffen the voltage.

There are other oscillations that are not sensitive to system strength where different types of controls (e.g. power system stabilisers or power oscillation dampers) are required to provide positive damping, and for which adding a GFM inverter or synchronous condenser by itself would not be beneficial.

The changing nature of oscillations on the power system does highlight the need for efficient processes that facilitate retuning of plant over its lifetime. One way that the technical standards can contribute to that is to document the range of conditions for which the plant has been tuned, so that, in the future, it can be easily identified when a coordinated review of settings is required because of a discrepancy between tuning ranges of connected plant and expected range of power system conditions. See discussion in section 0 of this report which deals with documenting system impedance levels.

The current NER are specified in the negative – i.e. not degrading damping or in the MAS not degrading damping of certain modes. It would make sense to require in the AAS facilities or control systems capable of providing positive damping for critical oscillation modes that are sensitive to system strength. Coordination of controls would still need to be undertaken by the TNSP, which should be part of its system strength service provider role. Coordinated controls are likely to be the least expensive form of system strength remediation.

Currently too, the MAS requires power system oscillations of the generating system against any other generating system to be adequately damped. However, there may already be inadequately damped (or undamped) oscillations on the power system, which may or may not be a problem, depending on their magnitude and whether they are bounded. Considering this reality, the MAS must deal with this possibility.

There is an overlap between this requirement and the system strength framework, whereby a generator may choose to either self-mitigate or pay for system strength services provided by a system strength service provider (a TNSP). In the case where the Generator or IRP is paying for the service, the generating system or IRS may have an adverse impact on some oscillation modes sensitive to system strength, which is the driver for the mitigation. However, the Generator will have no control over the impact on system strength-sensitive oscillation modes and it will need to be the responsibility of the system strength service provider to manage damping of those oscillations.

Discussion and feedback

At the prioritisation workshop this issue was ranked as high importance, but there was a wide range of opinion about why the current rule was not working. In a subsequent options assessment workshop, AEMO and stakeholders focused in on the confusion between electromechanical and system strength-sensitive oscillations and the application of the adequately damped criterion under the current NER.

Options

The following options have been identified, considering the workshop discussions:

1. Do nothing
2. Modify the AAS to require facilities capable of providing positive damping for critical modes of oscillation [that are sensitive to system strength]

  - Since identification of oscillation modes of IBR requires wide-area modelling, or measurement, NSP should advise the critical modes

3. In the MAS, a new generating system connecting to the power system should not make any poorly damped existing modes worse.
4. Carve out the MAS requirement for system strength-sensitive oscillations, where the generator has elected to pay for system strength mitigation.
   - In the case of oscillations sensitive to system strength if the generator or IRP opts not to self-mitigate system strength, it becomes the SSSP's responsibility to manage the plant's impact on oscillations sensitive to system strength.

Currently the AAS for asynchronous plant in NER S5.2.5.13(b)(4)(vii) requires:

> a power oscillation damping capability with sufficient flexibility to enable damping performance to be maximised:
>
> (A) with characteristics as described in paragraph (c); or
>
> (B) where *AEMO* has published characteristics for a *generating system* other than one comprised of *synchronous generating units*, following consultation in accordance with the *Rules consultation procedures*, with characteristics as published by *AEMO*.

For synchronous machines, paragraph (b)(3)(ix) of the AAS requires a power system stabiliser with characteristics described in the paragraph (c), without provision for AEMO to publish alternatives.

Paragraph (c) describes the structure typical of a power system stabiliser. Power system stabilisers typically damp electro-mechanical oscillations, which are different to system strength-sensitive control interaction oscillations. This clause does not preclude the development of controls to damp system strength-sensitive oscillations. However, because the understanding of these types of oscillations is still evolving, AEMO is unlikely to publish alternative characteristics suitable for control system interaction damping.

Option 2 could target this clause to system strength-sensitive oscillations and include facilities to damp those modes. As noted above, applying appropriate adjustments to controls (even if these need to be adjusted over time) is likely to be the least expensive way of mitigating system strength impacts for the NEM.

Option 3 would make the MAS work for conditions under which an existing oscillation is less than adequately damped, and Option 4 would make the requirements more consistent with the new system strength framework.

Recommendation

AEMO recommends NER amendments to give effect to Options 2, 3 and 4.

3.11 Definition of continuous uninterrupted operation

3.11.1 Recognition of frequency response mode, inertial response and active power response to an angle jump

Ref.	Group	Standard type	Objective(s)
#45	General	NA	• Align with best power system performance

Description

The CUO definition is used in NER S5.2.5.3, S5.2.5.4, S5.2.5.5 and S5.2.5.7, which relate to ride through requirements respectively for frequency disturbances, voltage disturbances, contingency events and partial load rejection. The definition is also used in NER S5.2.5.8, referring back to those other rules[39].

As currently drafted the CUO definition includes:

- not disconnecting, except as established under the protection-related performance standards (under NER S5.2.5.8, S5.2.5.9 and S5.2.5.10)
- during a disturbance, contributing active and reactive current as required by its performance standard established under NER S5.2.5.5
- after clearance of any electrical fault, only substantially varying its active power and reactive power as required or permitted by its performance standards established under NER S5.2.5.5, S5.2.5.11, S5.2.5.13, and S5.2.5.14
- not exacerbating or prolonging the disturbance or causing a subsequent disturbance for other connected plant except as required or permitted by its performance standards
- all auxiliary and reactive plant remaining in service.

Although the definition applies to multiple types of disturbance, it fails to adequately account for the types of responses that can occur under different types of disturbance, and which may be beneficial for some disturbances and permissible for others given those benefits.

The rule does not properly account for:

- (mainly) active power response opposing voltage phase angle jumps, which are expected behaviour for synchronous machines and GFM inverters
- inertial response, opposing change in frequency, proportional to rate of change of frequency (RoCoF), which is observed in synchronous machines and grid forming inverters, or other plant, that have synthetic inertia enabled.
- Frequency response mode operation during a disturbance

Specifically, NER S5.2.5.3 deals with frequency disturbances, but makes no mention of active power changes, and only refers to active and reactive current associated with a voltage disturbance in S5.2.5.5. Likewise NER S5.2.5.7 can be expected to involve frequency changes, but does not mention any power changes associated with voltage phase angle jumps, inertial response or frequency response mode operation.

Phase angle jumps can also be associated with contingency events, including line trips, including on clearance of a fault, generation trips and load trips. There is no permission or requirement for a response that opposes a voltage phase angle shift. This is a beneficial behaviour that helps to provide system strength (through voltage stability). However, it may cause a subsequent change in active power and reactive power following clearance of a fault, so the current wording of the CUO definition may be seen as not permitting this behaviour.

The response to a voltage phase angle change is for high X/R ratio networks mainly active power but can also have a component of reactive power response. The reactive component increases for lower X/R ratio networks.

[39] The term is used in the heading for S5.2.5.6, but not in the clause itself (AEMO may propose a redrafted heading).

Likewise inertial response is not mentioned in Schedule 5.2, although it is recognised elsewhere in the NER as providing benefit to the power system for frequency events. Inertial response can give rise to more oscillatory behaviour on the power system following a phase angle change. Under the present CUO definition, the less damped response associated with inertial response following clearance of a fault might be interpreted as exacerbating or prolonging a disturbance and therefore not permitted by the performance standards. Note that for GFM inverters inertial response is a settable control, and tuning of the control system will need to consider the best compromise between provision of inertia and damping of response to voltage phase angle change.

Discussion and feedback

Participants at the prioritisation workshop for general Schedule 5.2 issues ranked this issue as of medium importance. However, participants with a greater focus on GFM inverters ranked the issue high importance, reflecting its potential to be an impediment to GFM inverter connection.

Options

The options considered to address identified issues were:

1. Do nothing
2. Modify the CUO definition to:
   - permit responses opposing voltage phase angle jumps and frequency changes, including inertial response during disturbances, in clause (b)
   - permit inertial response and response opposing voltage phase angle jumps and inertial response, after clearance of any fault, in clause (c)
   - take into account inertial response and response to voltage phase angle jumps for subsequent response, in clause (d).
3. Modify each of NER S5.2.5.3, S5.2.5.4, S5.2.5.5, and S5.2.5.7 to specify what types of responses are permitted, considering the nature of the disturbance.

Option 1 is not preferred as it does not address the issue.

Options 2 and 3 are alternative drafting means of achieving a similar outcome.

Recommendation

The intent of Option 2 and 3 is the same. AEMO will consider for the detailed drafting which of these options would be most straightforward approach that achieves the desired outcome.

4 Recommendations – Schedule 5.3

Recommendations for Schedule 5.3 will be published as an addendum to this draft report as noted in Section 2.1.

5 Recommendations – Schedule 5.3a

It has been many years since NER Schedule 5.3a was last reviewed, and in that time there have been significant developments in high voltage direct current (HVDC) converter technology. AEMO has therefore reviewed the technical requirements of this schedule and recommends amendments to:

- broaden the application of technical requirements to all HVDC systems by decoupling requirements of HVDC systems from the market network service provider (MNSP) registration category; and
- incorporate the impact and capability of HVDC systems into technical requirements by aligning the requirements with generating systems.

The issues identified in relation to Schedule 5.3a primarily relate to technical performance of HVDC systems so that they contribute to power system security and the operation of the market.

The first recommendation is that Schedule 5.3a should apply to HVDC systems generally rather than specifically to the MNSPs. This decoupling from the MNSP registration category broadens the application of the requirements to all HVDC systems including regulated interconnectors and connections of multiple offshore wind generating systems. It is therefore likely to improve system security by providing more consistent and better coordinated performance of HVDC systems and, therefore, promotes the NEO.

The other recommendations align important aspects of the HVDC system performance standards with the equivalent requirements for generating systems and IRS in Schedule 5.2. Aligning the technical performance standards will mean the improved capability of modern HVDC systems can be made available to the power system. This would improve system security by increasing the resilience of HVDC systems at a small incremental cost.

5.1 NER S5.3a.1a – Introduction to the schedule

5.1.1 Alignment of schedule with plant type rather than registration category

Ref.	Group	Standard type	Objective(s)
#57	HVDC	AAS / MAS / NAS	• Broaden the application of technical requirements to all HVDC systems • Incorporate impact and capability of HVDC systems into technical requirements

AAS: Automatic Access Standard, MAS: Minimum Access Standard, NAS: Negotiated Access Standard

Description

At present, Schedule 5.3a specifically applies to MNSPs.

As most HVDC systems in the NEM are not registered as MNSPs and NER Schedule 5.1 does not cover such systems, it is appropriate to extend this standard to all HVDC systems rather than adapt NER S5.1 to duplicate the requirements in this schedule.

That is, the technical requirements covered by Schedule 5.3a should be expressed by reference to plant type irrespective of the registration category of the owner or operator, as the impact of a plant on the power system does not depend on the participant category.

If the performance standards are to be relied on for power system operation, then registration and ongoing compliance with performance standards should also be expected and required, irrespective of participant category.

Since HVDC system behaviour can impact power system security, it is appropriate for the technical requirements of these types of plant to be defined in Chapter 5 and registered with AEMO.

Discussion and feedback

In prioritisation workshops held by AEMO, participants indicated a high level of support in principle for addressing this issue.

Discussion indicated that the technical requirements for NSPs in NER Schedule 5.1 cover the general requirements of HVDC systems but not many of the specific requirements. Further, generator, network and customer roles have blurred since the commencement of the NEM so it is appropriate to align the technical requirements with the equipment type, rather than the participant registration category.

Options

The following options for the application of Schedule 5.3a were considered:

1. Do nothing – only apply the schedule to MNSPs.
2. Apply the requirements of the schedule to all to HVDC systems irrespective of registration classification.

Under Option 2, Schedule 5.3a would apply to HVDC systems including:

- Market network service facilities of registered MNSPs;
- Regulated HVDC systems owned and operated by a transmission network service provider (TNSP); and
- HVDC systems associated with generation, such as off-shore wind generating systems (where the HVDC system does not form part of the generating system).

The proposed amendment would clarify the technical performance requirements for HVDC systems, irrespective of who owns and operates them. This is likely to improve system security by providing more consistent and better coordinated performance of HVDC systems and, therefore, promotes the NEO.

Recommendation

AEMO recommends Option 2.

5.2 NER S5.3a.8 – Reactive power capability

5.2.1 Reactive power

Ref.	Group	Standard type	Objective(s)
#58	HVDC	AAS / MAS / NAS	• Incorporate impact and capability of HVDC systems into technical requirements

Description

At present the Automatic Access Standard (AAS) range in NER S5.3a.8 specifies 0.9 lagging power factor and 0.95 leading power factor for HVDC systems at the target voltage and rated power. No other conditions are mentioned, and the Minimum Access Standard (MAS) merely says that a capability less than the AAS can be agreed.

The reactive power capability of HVDC systems is important when managing the voltage profiles in the alternating current (AC) transmission networks being interconnected, in a similar manner to the reactive power capability of generating systems and should be aligned to the needs of the power system while supporting efficient investment decisions. This is because a change in the active power being transferred will impact on the AC voltage at the AC system terminals and a change in the reactive power injection or absorption is required to compensate.

In addition, the voltage source converters (VSCs) used in modern HVDC systems have the same capability to provide reactive power as those in inverter-based generation and battery energy storage systems (BESS).

However, the current reactive power capability in the AAS for HVDC systems is significantly lower than the equivalent AAS for generating systems in NER S5.2.5.1 (Reactive power capability). Therefore, the reactive power capability for generating system inverters in NER S5.2.5.1 could be applied to HVDC systems.

Discussion and feedback

In prioritisation workshops held by AEMO, participants indicated a high level of support in principle for addressing this issue. There was agreement that:

- The reactive power requirements for HVDC systems should be dependent on the grid requirements at the point of connection, not based on arbitrary limits.
- The requirements for HVDC systems should be updated from the capability of line-commutated convertors to take into account the capabilities of VSCs. This could be achieved by aligning the requirement with NER S5.2.5.1 for generators, including a minimum access standard of zero capability.
- The need for HVDC systems to absorb reactive power at 0.9 pu voltage and generate reactive power at 1.1 pu voltage should align with the discussion on NER S5.2.5.1 (see Section 3.2.2 of this report).

Options

The following options for HVDC system reactive power access standards were considered:

1. Do nothing.
2. Apply the requirements of NER S5.2.5.1 to HVDC systems.
3. Modify the AAS to include a voltage-dependent requirement for reactive power, equivalent to that being considered for NER S5.2.5.1.

4. Modify the AAS to consider the impact of voltage droop settings on the potential range for full reactive output.

Option 1 is not preferred, because the prioritisation workshops indicated a high level of support for improving this rule.

Options 2, 3 and 4 address the issue by aligning the reactive power requirements for HVDC systems with those for generating systems in NER S5.2.5.1, noting that the requirements of NER S5.2.5.1 are being considered elsewhere in this review. Options 3 and 4 explore equivalent options being considered for the concurrent review of NER S5.2.5.1.

Option 2 allows the reactive power capability available from the VSCs in modern HVDC systems to be made available to the power system. This would improve system security by improving the control of the network voltage at the HVDC system AC terminals. The incremental cost of the additional reactive power capability is expected to be relatively small and, as the MAS would require no capability, the Negotiated Access Standard (NAS) would only specify a reactive power capability that is necessary for the power system conditions of the HVDC system connection.

Recommendation

AEMO recommends Option 2.

5.3 NER S5.3a.13 – Market network service response to disturbances in the power system

5.3.1 Voltage disturbances

Ref.	Group	Standard type	Objective(s)
#59	HVDC	AAS / MAS / NAS	• Incorporate impact and capability of HVDC systems into technical requirements

Description

Currently the voltage ride-through requirement in NER S5.3a.13 for an HVDC system is for continuous uninterrupted operation (not italicised) for the range of voltage conditions permitted in the system standards. The system standards for voltage magnitude in NER S5.1a.4 only contemplate the allowable voltages following credible contingency events.

The voltage disturbance requirement in NER S5.2.5.4 (Generating system response to voltage disturbances) for generators includes withstand requirements beyond those in the system standards for credible contingency events. This improves the security of the power system by adding resilience for non-credible contingency events that can be somewhat more severe. This additional resilience of HVDC systems is of similar importance to that of generating systems, and other network and load plant. For example, the tripping of a 500 megawatts (MW) import on a HVDC system like Basslink would have an equivalent impact to the loss of 500 MW of generation in the Victorian power system.

The VSCs used for modern HVDC systems operate with the same principles as the VSCs used in solar, wind and BESS. The older line-commutated technologies may not be able to meet the AAS in NER S5.2.5.4, but AEMO understands that this technology is unlikely to be deployed in the NEM again.

One difference between generating systems and HVDC systems is that HVDC system converter stations generally have high voltage harmonic filters connected to improve the harmonic performance, as well as providing reactive power support. These harmonic filters may not be rated to meet the AAS in NER S5.2.5.4 for over-voltages and may be tripped by their protection systems. The tripping of a harmonic filter during an over-voltage may not automatically mean that the HVDC system must also trip and, in any case, it would lower the voltage in the network and it could be reconnected after the disturbance.

Therefore, the performance requirements for HVDC systems would be enhanced by aligning the voltage disturbance requirements with those in NER S5.2.5.4 for generators, including both AAS and MAS.

Discussion and feedback

In prioritisation workshops held by AEMO, participants indicated a high level of support in principle for addressing this issue. It was agreed:

- That the access standards for HVDC systems should not be limited to credible contingencies but aligned with the requirements for generating systems in NER S5.2.5.3 (Generating system response to frequency disturbances) and NER S5.2.5.4, noting that harmonic filters may disconnect for the over-voltages specified in the AAS in NER S5.2.5.4.
- To consider whether the continuous uninterrupted operation (CUO) requirements could be relaxed for HVDC systems, including those associated with interconnectors and off-shore wind.

Options

The following options for HVDC system voltage disturbance access standards were considered:

1. Do nothing, that is, only expect HVDC to ride through credible contingencies.
2. Require HVDC to have the same AAS and MAS as generating systems in NER S5.2.5.4.
3. Same as Option 2, but requiring MAS of no capability.
4. Same as Option 2, but relaxing CUO to allowing for the tripping of harmonic filters.

Option 1 is not preferred as it does not capture the capability of HVDC systems to ride through the same voltage disturbances as generating system, even though the inverter technology is essentially the same.

Option 2 would align the requirements for HVDC systems with those for generating systems and IRS, noting that the requirements of NER S5.2.5.4 are being considered elsewhere in this review. This would allow the voltage disturbance ride-through capability of the VSCs used in HVDC systems to be made available to the power system. and improve system security by increasing the resilience of HVDC systems during voltage disturbances. Also, the likely incremental cost of the additional resilience would be relatively low given that all future HVDC systems are expected to use VSCs.

Option 3 also aligns the AAS requirements for HVDC systems with those for the AAS for generating systems and IRS, but relaxes the MAS for HVDC systems to no capability to provide flexibility where an HVDC system cannot meet the MAS in NER S5.2.5.4 but it does not introduce a power system security risk.

Option 4 also aligns the AAS requirements for HVDC systems with those for the AAS for generating systems and IRS, but relaxes the MAS for HVDC systems by relaxing CUO to the extent that harmonic filters are able to disconnect for high voltage above the MAS in NER S5.2.5.4.

Option 2 is preferred over options 3 and 4 because AEMO considers that the VSCs used in HVDC system are very likely to at least meet MAS for generating systems without the need to further relax the requirements.

Recommendation

AEMO recommends Option 2.

5.3.2 Frequency disturbances

Ref.	Group	Standard type	Objective(s)
#60	HVDC	AAS / MAS / NAS	• Incorporate impact and capability of HVDC systems into technical requirements

Description

Currently the frequency ride-through requirement for a HVDC systems is for continuous uninterrupted operation (not italicised) for power system frequency within the frequency operating standards.

The security of the power system depends on the ability of the network, load and generation plant to operate continuously following frequency disturbances, including those following non-credible contingencies. That is, the reliance of the power system on the CUO of HVDC systems is of similar importance to that of generation. In addition, the ability of HVDC systems to maintain CUO during frequency disturbances is expected to be similar to that of modern VSCs.

In respect of the frequency disturbances, generating systems and IRS have the requirements in NER S5.2.5.3. Therefore, the frequency ride-through requirements for HVDC systems could be aligned with the frequency disturbance requirements in NER S5.2.5.3. This is already consistent with the current requirements, except that NER S5.2.5.3 includes additional rate of change of frequency (RoCoF) requirements.

Discussion and feedback

In prioritisation workshops held by AEMO, participants indicated a medium to high level of support in principle for addressing this issue. Stakeholders could not identify an apparent reason not to align the frequency disturbance requirements for HVDC systems to those for generators, including the RoCoF requirements.

Options

The following options for the application of Schedule 5.3a were considered:

1. Do nothing.
2. Align the frequency disturbance requirements for HVDC systems with the requirements for generating systems and IRS in NER S5.2.5.3, and exempt regulated NSPs from the requirements of NER S5.1.3 in respect of their HVDC systems.

Option 1 is not preferred as it does not capture the capability of HVDC systems to ride through the same frequency disturbances as generating systems, even though the VSC technology is essentially the same.

Option 2 would align the requirements for HVDC systems with those for generating systems and IRS, noting that the requirements of NER S5.2.5.3 are being considered elsewhere in this review. This allows the frequency disturbance ride-through capability of the VSCs used in HVDC systems to be made available to the power system. This will improve system security by increasing the resilience of HVDC systems during frequency disturbances. Also, the incremental cost of the additional resilience is expected to be relatively small given that all future HVDC systems are expected to use VSCs.

AEMO notes that NER S5.1.3 requires that an NSP must ensure that all of its power system equipment will remain in service when the frequency is within the *extreme frequency excursion tolerance limits*, unless the equipment forms part of an emergency frequency control scheme. While the requirement does not specify a time limit for this obligation, implying continuous operation in this range, in practice this obligation would be limited as generating units may trip beyond 2 minutes outside the range of 48-52 hertz (Hz). Therefore, AEMO also recommends that under this option, regulated NSPs be exempt from the requirement of NER S5.1.3 in respect of their HVDC systems, to align with the recommended requirements for all HVDC systems.

Recommendation

AEMO recommends Option 2.

5.3.3 Fault ride-through requirements

Ref.	Group	Standard type	Objective(s)
#61	HVDC	AAS / MAS / NAS	• Incorporate impact and capability of HVDC systems into technical requirements

Description

NER S5.3a.13 defines the required performance for HVDC systems in regard to disturbances in the power system. This clause does not include a requirement for fault ride-through capability.

The security of the power system depends on the ability of the network, load and generation plant to operate continuously following faults that are somewhat likely to occur, including multiple faults associated with non-credible contingencies. In this respect generating systems and IRS have the requirements in NER S5.2.5.5 (response to disturbances following contingency events).

Similarly, the VSCs used in modern HVDC systems operate using the same principles as the inverters in solar, wind and BESS. Therefore, a requirement to be capable of riding through faults could either be added to clause NER S5.3a.13 or in a new clause added to NER S5.3a.

A new requirement to be capable of riding through faults would need to consider single phase, phase to phase, 2 phase to ground and 3 phase fault requirements for transmission and distribution systems, in a similar manner to the requirements in NER S5.2.5.5. This new requirement also needs to consider any conditions under which multiple fault ride-through may not be achieved.

Older HVDC system technologies, such as that used in Basslink with line commutated convertors, operate using different principles to VSCs and may not be able to meet the AAS in NER S5.2.5.5. However, future HVDC systems are unlikely to use these types of convertors. In addition, the older technologies may still be able to meet the MAS.

An issue related to HVDC systems is the potential need to consider faults within the DC transmission lines or cables. The ability to manage DC system faults could also impact the security of the power system.

Discussion and feedback

In prioritisation workshops held by AEMO, participants indicated a high level of support in principle for addressing this issue. It was agreed that:

- HVDC systems should meet, or even exceed, the performance requirements of generators and thus should include MFRT capability. This requirement should be irrespective of the whether the HVDC system is an MNSP, or owned, controlled or operated by a TNSP, or associated with generating systems.
- Requirements for DC faults should not be included in the HVDC system access standards, as equivalent requirements for faults behind the connection point do not apply to generating systems.

Options

The following options for HVDC system fault ride through access standards were considered:

1. Do nothing.
2. Require HVDC systems to have the same access standards as generating systems and IRS (that is, equivalent to the AAS and MAS in NER S5.2.5.5).
3. Same as Option 2, but have MAS of no capability.

Option 1 is not preferred because there was stakeholder support to address this issue, as currently the capability of HVDC systems to ride faults in the same manner as generating systems is not captured in the access standards.

Options 2 and 3 address the associated issues. It should be noted under Options 2 and 3 that the equivalent requirements in NER S5.2.5.5 are being considered in this review.

Option 3 also relaxes CUO to the extent that harmonic filters are able to disconnect following network faults.

Option 2 would allow the MFRT capability of the VSCs used in HVDC systems to be made available to the power system. It would improve system security by increasing the resilience of HVDC systems following faults. Also, the likely incremental cost of the additional resilience would be relatively low, given that all future HVDC systems are expected to use VSCs.

Recommendation

AEMO recommends Option 2.

AEMO does not recommend including requirements for DC side faults in HVDC systems, as no equivalent requirement exists for generating systems.

5.4 NER S5.3a.4 – Monitoring and control requirements

5.4.1 Remote monitoring and protection against instability

Ref.	Group	Standard type	Objective(s)
#64	HVDC	AAS / MAS / NAS	• Incorporate impact and capability of HVDC systems into technical requirements

Description

Remote monitoring and protection against inverter instability is an important topic, and the requirement for asynchronous generating units in NER S5.2.5.10 (Protection to trip plant for unstable operation) is being considered in this review. However, remote monitoring and protection against instability for HVDC systems is not currently in NER S5.3a.4 and could be similar to requirements for asynchronous plant for NER S5.2.5.10.

Discussion and feedback

In prioritisation workshops held by AEMO, participants indicated a medium level of support in principle for addressing this issue. It was agreed that:

- HVDC systems should not automatically be disconnected for instability, as this could impact on the reliability and security of the power system.
- Installing power oscillation dampers (PODs) for HVDC systems should be encouraged for managing potential instabilities.

This is discussed further in Section 5.5.1 below on voltage control.

Options

The following options for remote monitoring and protection against instability were considered:

1. Do nothing.
2. Align remote monitoring and protection against inverter instability requirements for HVDC systems to the equivalent requirements for generating systems and IRS in NER S5.2.5.10.

Option 1 is not preferred because there was stakeholder support to address this issue, as currently Schedule 5.3a does not require monitoring and protection of inverter instability.

Option 2 would align the monitoring and protection requirements for HVDC systems to those for asynchronous generating plant, which is likely to advance the NEO by providing a co-ordinated approach to IBR instability that can be applied to all plant likely to participate in a controller instability.

Note that this option does not include a requirement for the automatic disconnection for an instability of an HVDC system that forms an interconnector, because the disconnection of an interconnector is likely to have significant impacts on the operation and security of the power system.

Recommendation

AEMO recommends Option 2.

5.5 New standards

5.5.1 Voltage control

Ref.	Group	Standard type	Objective(s)
#62	HVDC	AAS / MAS / NAS	• Incorporate impact and capability of HVDC systems into technical requirements

Description

Currently Schedule 5.3a does not specify the AC voltage control requirements for HVDC systems.

A change in the active power transfer over a HVDC system will have a material impact on the AC voltage at both its AC terminals. Therefore, the HVDC system should control the voltage or reactive power at its AC terminals to compensate. In addition, the voltage source converters used in HVDC systems have the capability to provide AC voltage control independently at each AC terminal. A possible new standard could be included with requirements similar to those specified for asynchronous generating systems in NER S5.2.5.13 (Voltage and reactive power control).

In addition, AEMO notes that NER S5.2.5.13 for generating systems and IRS specifies three AC voltage control models:

- Voltage control mode.
- Reactive power control mode.
- Power factor control mode.

It will be necessary to consider which of these potential control modes should be included in the AAS and MAS for HVDC systems.

Discussion and feedback

In prioritisation workshops held by AEMO, participants indicated a medium level of support in principle for addressing this issue.

It was agreed at the options assessment workshop that VSCs can provide voltage control as a standard offering. Stakeholders could not identify an apparent reason not to mandate its provision.

It was also noted that that some NSPs may require both AC voltage and reactive power control modes.

One stakeholder advised that it is common practice for HVDC system convertors to minimise the current prior to blocking. This will require a capability to control reactive power.

Options

The following options for HVDC system AC voltage control through access standards were considered:

1. Do nothing.
2. Apply the voltage control requirements of NER S5.2.5.13 to HVDC systems, noting that NER S5.2.5.13 is subject to this review.
3. Same as Option 2 but limit the control modes to voltage control.

Option 1 is not preferred as the prioritisation workshops indicated some support for addressing this issue.

Option 2 would enable the inherent AC voltage control capability of the VSCs used in HVDC systems to be made available to the power system. This would improve system security by increasing the resilience of HVDC systems following changes in system conditions. Also, the likely incremental cost of the additional resilience would be relatively low given that all future HVDC systems are expected to use VSCs. Under this option, the AAS would only require AC voltage and reactive power control modes. This alignment would also include damping requirements and the provision of power oscillation damping.

Option 3 would also align the requirements with those for generating systems but would limit the requirement only an AC voltage control. This option was not preferred as some stakeholders considered that both AC voltage and reactive power control modes may be required in some circumstances.

Recommendation

AEMO recommends Option 2.

5.5.2 Active power dispatch

Ref.	Group	Standard type	Objective(s)
#63	HVDC	AAS / MAS / NAS	• Incorporate impact and capability of HVDC systems into technical requirements

Description

The flow of active power on HVDC systems needs to be controlled in a similar manner to the dispatch and ramping of scheduled generators, and currently this requirement is not included in NER S5.3a. Therefore, active power control requirements for HVDC systems could be aligned with those for generating systems and IRS in NER S5.2.5.14 (Active power control).

Discussion and feedback

In prioritisation workshops held by AEMO, participants indicated a high level of support in principle for addressing this issue. Stakeholders agreed that the active power control requirements for HVDC systems should be aligned to those for generators in NER S5.2.5.14.

Options

The following options for the application of Schedule 5.3a were considered:

1. Do nothing.
2. Align the active power dispatch requirements for HVDC systems with the requirements for generating systems in NER S5.2.5.14.

Option 1 is not preferred as the prioritisation workshops indicated high support for addressing this issue.

Option 2 would align the requirements for HVDC systems with those for generating systems in NER S5.2.5.14. This would allow the inherent active power control capability of the VSCs used in HVDC systems to be made available to the power system. This would improve the dispatch of HVDC systems which is expected to improve the efficiency of the NEM while maintaining power system security.

Recommendation

AEMO recommends Option 2.

6 Recommendations – Multiple schedules

6.1 Multiple clauses

6.1.1 References to superseded standards

Ref.	Group	Standard type	Objective(s)
#01, #14, #15	General	AAS & MAS	• Streamline the connection process

Description

Australian/New Zealand Standards AS/NZS 61000.3.6.2001, AS/NZS 61000.3.7.2001 are referenced in NER S5.1.6 and S5.1.5 respectively, and also NER S5.1a.6 and S5.1a.5.

Schedules 5.2, 5.3 and 5.3a refer back to S5.1.5 and S5.1.6 for the relevant voltage fluctuation and voltage harmonics clauses of those schedules.

Table 10 References to Australian/New Zealand Standards

Standard	Reference	Referenced through Schedule 5.1 or 5.1a
AS/NZS 61000.3.6.2001 Electromagnetic compatibility (EMC) Limits - Assessment of emission limits for distorting loads in MV and HV power systems (IEC61000-3-6:1996, MOD)	• S5.1.6, S5.1a.6	• S5.2.5.2 • S5.2.5.6 • S5.3.8 • S5.3a.11 • S5.3a.13 • S5.3a.14
AS/NZS 61000.3.7.2001 Electromagnetic compatibility (EMC) - Limits - Assessment of emission limits for fluctuating loads in MV and HV power systems (IEC 61000-3-7:1996, MOD)	• S5.1.5, S5.1a.5	• S5.2.5.2 • S5.2.5.6 • S5.2.5.10 • S5.3.7 • S5.3a.10 • S5.3a.14

The Standards listed above have been superseded by Technical Reports (TR), as follows:

- TR IEC 61000.3.6.2012 replacing AS/NZS 61000.3.6.2001
- TR IEC 61000.3.7:2012 replacing AS/NZS 61000.3.7.2001

Standards Australia is the published of TR and AS/NZS, however, the formers informative rather than normative like an AS/NZS. For the purposes of compliance assessment, there is some confusion within industry over whether an existing TR or superseded AS/NZS should be used.

Relevantly, NER 1.17(i) states that a reference to a document or a provision of a document includes an amendment or supplement or replacement or novation of, that document or that provision of a document. Nevertheless, the application of this rule (and new TR or ASNZS) is clearer where the dates are not referenced with associated technical requirements.

Discussion and feedback

This issue was ranked relatively low importance at prioritisation sessions. There was also no opposition to addressing the issues.

Options

Noting that the current document has a slightly different designation, the main options are:

1. Do nothing
2. Amend the references in S5.1.5, S5.1.6 S5.1a.5 and S5.1a.6 to the latest versions with dates
3. Amend the references in S5.1.5, S5.1.6 S5.1a.5 and S5.1a.6 to the latest versions without dates

Option 1 does not address the issue.

Options 2 and 3 differ only with respect to referencing the date. Considering NER 1.17(i), the options should result in the same interpretation, but confusion is avoided if dates are excluded.

Recommendation

AEMO recommends Option 3.

7 Omitted issues

Of the 68 issues identified in and following the approach paper, 14 have not been further considered in the draft report, and for two a 'do nothing' option was preferred after consideration. Issues were omitted primarily on the basis that stakeholder consultation and AEMO analysis indicated that the issues created little to no impact on stakeholders and it would be complex or burdensome to develop solutions in the Review timeframe.

The table below sets out these issues and the rationale for omission.

Table 11 Summary of omitted issues

Ref.	Rule	Issue	Omission rationale
10	S5.2.5.1	Clarity on requirement with reduced number of units in service	Can be sensibly worked out without prescription.
16	S5.2.5.2	Balance of ESS load currents (when charging)	The requirements have changed, but it is unclear if there is a problem with the new (untested) requirements.
17	New	Rapid voltage changes	A power quality issue better progressed by NSPs.
26	S5.2.5.5	Overload capability in asynchronous production units (rapid active power injection)	To be considered in a separate piece of work on grid forming inverters.
34	S5.2.5.9	Redundancy clarification	Ranked as low importance in technical focus group prioritisation workshop.
36	S5.2.5.11	Droop range	Ranked as low importance in technical focus group prioritisation workshop – covered by existing NER requirement.
37	S5.2.5.11	Energy source availability	'Do nothing' option recommended. See discussion in Appendix A3.1.
44	S5.2.5.13	Guidance on voltage droop requirement when a reduced number of generating units is in service	Too much detail for the NER.
47	Definitions	Definition of synchronous /asynchronous	'Do nothing' option recommended. See discussion in Appendix114A3.2 .
50	New	Capability to operate in a grid without synchronous machines (islanding) and capability to synchronise to a grid	To be considered in future work on GFM inverters.
51	New	Capability for black start	Black start services are only needed from a subset of generating systems, not as a general technical standard requirement. Requiring the capability from all generation may not be consistent with the NEO.
52	New	Minimum phase jump without current limiting	To be considered in future work on GFM inverters.
53	New	Inertial response	To be considered in future work on GFM inverters.
55	New	Grid forming devices other than generation/batteries	To be considered in future work on GFM inverters.
56	S5.2.5.8 or new clause	Response on failure of communications or other systems	The NER adequately covers the performance impacts that could arise from loss of communications. Preference is for performance standards to specify performance outcomes rather than design requirements.

Ref.	Rule	Issue	Omission rationale
65	New (5.3a)	Islanding and black-start performance, grid forming capability	Provision of black system services by HVDC systems should be on similar basis as generators and other NSPs. AEMO also notes that the benefits of providing black system services will be dependent on the location of the link within the power system.

7.1 Accommodation of GFM technology connections

For the connection of GFM technology, AEMO has focussed its Review recommendations on amending or adapting relevant technical requirements to ensure they do not inadvertently hinder its connection and the beneficial capabilities it might provide. AEMO acknowledges the importance of further work to develop core requirements to support the connection of GFM technology and will therefore consider whether there is a need for its additional consideration of the technical requirements of NER Schedule 5.2, outside of this Review. AEMO envisages that any such work would leverage collaboration with technical representatives similar to the stakeholder engagement approach used to develop recommendations for the Review.

The decision to focus the Review on removing impediments to the connection of GFM technology was informed by:

- Stakeholder discussions (relating to the Review, voluntary GFM technical specification and system strength guideline), indicating the need for further work to better identify GFM technology capabilities, costs and benefits.
- The regulatory timeframe for the Review, which is scheduled for completion by October 2023 (within 12 months of the approach paper). This timeframe is unlikely to allow for a prudent level of validation and testing before making final recommendations.

A1. Summary of issues considered

AEMO considered 68 issues in preparing the draft report (including the addendum which will be published subsequent to this report. The table below summarises each issue considered and its outcome.

Table 12 Summary of all issues considered in developing draft report and addendum

Ref.	Rule	Issue	Group	Outcome
1	S5.3.7, S5.3.8, S5.3.9	Correct references to superseded standards	Load	Recommendation
2	s5.3.9	Large load contingencies	Load	TBD in addendum
3	s5.3.9 or new clause	Stability of IBR loads	Load	TBD in addendum
4	s5.3.9 or new clause	Fault ride through	Load	TBD in addendum
5	S5.3.9	Operation of large loads during frequency disturbances	Load	TBD in addendum
6	S5.3.10	Under-frequency ramp down	Load	TBD in addendum
7	Possible new clause	Limiting active power ramp rate	Load	TBD in addendum
8	Schedule 5.3 or 5.2	Treatment of large Uninterruptible Power Supplies	Load	TBD in addendum
9	S5.2.5.1	Relationship between reactive power requirement and voltage	General	Recommendation
10	S5.2.5.1	Clarity on requirement with reduced number of units in service	General	Omitted
11	S5.2.5.1	Clarity on temperature impacts	General	Recommendation
12	S5.2.5.1	Clarity on offline reactive impact when units are not operating	General	Recommendation
13	S5.2.5.2	S5.2.5.2 Plant standards	General	Recommendation
14	S5.2.5.2, S5.2.5.6, S5.2.5.10, S5.3.7, S5.1.5	Voltage fluctuation standard	General	Recommendation
15	S5.2.5.2, S5.2.5.6, S5.3.8, S5.3a.11, S5.1.6	Harmonics emission standard	General	Recommendation
16	S5.2.5.2	Balance of ESS load currents (when charging)	General	Omitted
17	TBD	Rapid voltage changes	General	Omitted
18	S5.2.5.4	Voltages over 130%	General	Recommendation
19	S5.2.5.4	Point of application of over-voltages	General	Recommendation
20	S5.2.5.5	Definition of end of a power system disturbance	General	Recommendation
21	S5.2.5.5	Form of the MFRT clause	General	Recommendation
22	S5.2.5.5	Multiple Fault Ride reducing the fault level below the level for which the plant is tuned	General	Recommendation
23	S5.2.5.5	Clarity on reactive current injection volume and location	General	Recommendation
24	S5.2.5.5	Overvoltage management during and after faults (unbalanced faults)	General	Recommendation
25	S5.2.5.5	Active power recovery after a fault	General	Recommendation
26	S5.2.5.5	Overload capability in asynchronous production units (rapid active power injection)	GFM	Omitted
27	S5.2.5.5	Commencement of reactive current injection	Gen & GFM	Recommendation
28	S5.2.5.5	Risetime and settling time	Gen & GFM	Recommendation
29	S5.2.5.7	Application of minimum generation to ESS	General	Recommendation
30	S5.2.5.7	Clarification of requirement to remain in CUO	General	Recommendation

Ref.	Rule	Issue	Group	Outcome
31	S5.2.5.8	Improve drafting of fast over-frequency response subclauses (rapid proportional over-frequency response)	General	Recommendation
32	S5.2.5.8	Emergency over-frequency response for hydro stations	General	Recommendation
33	S5.2.5.8	Application of emergency over-frequency response by plant size and connection voltage	General	Recommendation
34	S5.2.5.9	Redundancy clarification	General	Omitted
35	S5.2.5.10	Requirements for stability protection on asynchronous production units (oscillation monitor and protection)	General	Recommendation
36	S5.2.5.11	Droop range	General	Omitted
37	S5.2.5.11	Energy source availability	General	Omitted
38	S5.2.5.13	Voltage control at unit level and slow setpoint change	Gen & GFM	Recommendation
39	S5.2.5.13	Realignment of performance requirements to optimise power system performance over expected range of fault level (establishing rise time and settling times)	General	Recommendation
40	S5.2.5.13	Materiality threshold on settling time	General	Recommendation
41	S5.2.5.13	Voltage settling time requirements for reactive power control or power factor control	General	Recommendation
42	S5.2.5.13	Clarification of when multiple modes of operation are required	General	Recommendation
43	S5.2.5.13	Impact of a generating system on power system oscillatory stability	General	Recommendation
44	S5.2.5.13	Guidance on voltage droop requirement when a reduced number of generating units is in service	General	Omitted
45	Ch 10 definition (CUO)	Recognition of inertial response and PFR in CUO definition	Gen & GFM	Recommendation
46	S5.2.5.5	Metallic conducting path	General	Recommendation
47	Synchronous and asynchronous	Definition of synchronous /asynchronous	Gen & GFM	Omitted
48	S5.2.1	Alignment of Schedule 5.2 with plant, including synchronous condensers, rather than registration type	General	Recommendation
49	S5.2.5.1, S5.2.5.5, S5.2.5.7, S5.2.5.13	Consideration of reduced requirements for small connections	General	Recommendation
50	Possible new standard	Capability to operate in a grid without synchronous machines (islanding) and capability to synchronise to a grid	GFM	Omitted
51	Possible new standard	Capability for black start	GFM	Omitted
52	Possible new standard	Minimum phase jump without current limiting	GFM	Omitted
53	Possible new standard	Inertial response	GFM	Omitted
54	Possible new standard	Commencement time for response to a fault	GFM	Recommendation
55	Possible new standard	Grid forming devices other than generation/batteries	GFM	Omitted
56	Possible new standard or new part of S5.2.5.8	Response on failure of communications or other systems	General	Omitted
57	S5.3a.1a	Alignment of schedule with plant-type rather than registration category	HVDC	Recommendation
58	S5.3a.8	Reactive power (S5.3a.8)	HVDC	Recommendation
59	S5.3a.13	Voltage disturbances (within S5.3a.13)	HVDC	Recommendation
60	S5.3a.13	Frequency disturbances (within S5.3a.13)	HVDC	Recommendation
61	S5.3a.13	Fault ride through requirements (currently not specified, include in S5.3a.13, or add a new clause)	HVDC	Recommendation

Ref.	Rule	Issue	Group	Outcome
62	Possible new standard	Voltage control	HVDC	Recommendation
63	Possible new standard	Active power dispatch	HVDC	Recommendation
64	S5.3a.4	Remote monitoring and protection against instability (not currently considered)	HVDC	Recommendation
65	Possible new standard	Islanding and black-start performance, grid forming capability	HVDC	Omitted
66	S5.2.5.5	Number of faults with 200 ms between them (MAS)	General	Recommendation
67	S5.2.5.4	Clarification of continuous uninterrupted operation in the range 90% to 110% of normal voltage	General	Recommendation
68	S5.2.5.5	Reclassified contingency events	General	Recommendation

A2. Technical focus group consultation

AEMO facilitated a series of workshops, inviting its technical focus group members to inform the recommendations made in the draft report. Pre-reading material was circulated to attendees for all sessions in advance to facilitate an informed discussion and efficient use of attendees' time. Workshops made use of survey tools to capture and analyse attendee feedback on issues raised, which was used in preparing this draft report.

A2.1 Prioritisation workshops

Four prioritisation workshops were facilitated by AEMO as set out in the below table.

Table 13 Prioritisation Workshops

Technical Focus Group	Relevant Schedules	Date
Large Loads	Schedule 5.3 (including proposed new standards)	31 Oct 2022
General	Schedule 5.2 (including proposed new standards)	2 Nov 2022
Grid-forming inverter	Schedule 5.2 (including proposed new standards)	3 Nov 2022
HVDC	Schedule 5.3a (including proposed new standards)	7 Nov 2022

A2.2 Options Assessment Workshops

Options assessment workshops were facilitated by AEMO to discuss and develop solutions for more complex issues. These are summarised below in the below table.

Table 14 Options Assessment Workshops

Technical Focus Group	NER clause	Issue	Date
General	S5.2.5.13	• Realignment of performance requirements to optimise power system performance over expected range of fault level (establishing rise time and settling times) • Clarification of when multiple modes of operation are required	5 Dec, 2022
	S5.2.5.1	• Relationship between reactive power requirement and voltage • Clarity on offline reactive impact when units are not operating	5 Dec, 2022
	S5.2.5.4	• Voltages over 130% • Point of application of over-voltages	7 Dec, 2022
	S5.2.5.5	• Definition of end of a power system disturbance Number of faults with zero time /200 ms between them (MFRT) and form of the MFRT clause • Multiple Fault Ride reducing the fault level below the level for which the plant is tuned	12 Dec, 2022
	S5.2.5.1, S5.2.5.5, S5.2.5.7, S5.2.5.13	• Consideration of reduced requirements for small connections	13 Dec, 2022
	S5.2.5.10	• Requirements for stability protection on asynchronous production units (oscillation monitor and protection)	11 Jan, 2023
	S5.2.5.5	• Clarity on reactive current injection volume and location	17 Jan, 2023

Technical Focus Group	NER clause	Issue	Date
General & GFM	Continuous uninterrupted operation definition Ch 10	• Recognition of inertial response and PFR in CUO definition • Capability to operate in a grid without synchronous machines (islanding) and capability to synchronise to a grid	14 Dec, 2022
	S5.2.5.13	• Impact of a generating system on power system oscillatory stability Voltage control at unit level and slow setpoint change	15 Dec, 2022
	S5.2.5.5	• Commencement of reactive current injection Risetime and settling time	12 Jan, 2023
Large Load	S5.3.9 or new clause	• Fault ride through • Treatment of large Uninterruptible Power Supplies	13 Dec, 2022
	s5.3.9	• Operation of large loads during frequency disturbances • Under-frequency ramp down	14 Dec, 2022
	s5.3.9 & S5.3.11 Possible new clause	• Stability of IBR loads • Limiting active power ramp rate	20 Dec, 2022
HVDC	S5.3a.8	• Voltage disturbances (within S5.3a.13) • Fault ride through requirements	17 Jan, 2023
	S5.3a.8	• Reactive power (S5.3a.8) • Voltage control	18 Jan, 2023

A3. Recommendations to 'do nothing'

A3.1 NER S5.2.5.11 – Frequency control - Energy source availability

Description

Transgrid in a response to the approach paper identified that the MAS for NER S5.2.5.11 includes the phrase "subject to energy source availability" in regard to provision of frequency control ancillary services and queried whether this should be included in the AAS.

Discussion and feedback

Participants at the prioritisation workshop ranked this issue of low importance. Three participants opposed a change on the grounds that if the generating system offers raise services for frequency control ancillary services (FCAS) then it needs to keep headroom sufficient to provide those services. The AAS as written would require the plant to have capabilities to maintain that headroom. In a VRE plant, this could be some additional hardware and software components.

Options

The options considered to address identified issues were:

1. Do nothing
2. Add the phrase "subject to energy source availability" to the AAS.

Considering the workshop comments, the performance outcome could be different depending on whether or not the AAS requirement for capability to provide FCAS is subject to energy source availability. It is more beneficial to the power system to have this capability, as more plant will be able to provide raise services without modification. In practice a need to modify plant before offering a raise service is likely to be an impediment to provision of that service, and retrofitting equipment and software changes is generally more expensive than installing them initially.

Recommendation

AEMO recommends Option 1.

A3.2 Clarification of the term synchronous generating unit

Description

In its submission on the approach paper, Transgrid considered that the 'synchronous' and 'asynchronous' definitions are deficient.

The relevant NER Chapter 10 definitions read as follows:

> ***Synchronous production unit***
>
> A *production unit* comprising alternating current generators which operate at a speed which is synchronised to the *frequency* of the *power system*.

Synchronous generating unit

A generating unit that is a synchronous production unit.

Asynchronous production unit

A *production unit* that is not a *synchronous production unit.*

Asynchronous generating unit

A *generating unit* that is not a *synchronous generating unit*.

The terms "synchronous production unit", "asynchronous production unit" were introduced, and "synchronous generating unit" and "asynchronous generating unit" were redefined, as part of the IESS Rule.

AEMO notes that the "synchronous" definitions still refer to speed of operation, implying rotating machines.

Discussion and feedback

A key driver for the interest in the synchronous generating unit definition and associated definitions is whether a GFM inverter should be considered synchronous under the NER. This was also reflected in some of the comments from the prioritisation workshop. From a physical perspective, GFM inverters are asynchronous. However, GFM inverters that are configured as virtual synchronous machines have characteristics that are in some respects very similar to synchronous generating units. Examples of similar performance include response to voltage magnitude steps or voltage phase angle jumps. Other aspects of GFM inverters and synchronous machines are different. GFM inverters are more flexibly configurable than synchronous machines, and may not suffer from some of the limitations of synchronous machines that the technical standards allow for. On the other hand, unless specifically designed for, GFM inverters do not inherently have the same short-term overload capabilities, so behaviour at limits of operation becomes much more critical.

Because of the differences, AEMO prefers not to vary the synchronous generating unit definition to incorporate GFM inverters, but rather to remove impediments to GFM inverter connection that arise as a result of the current standards for asynchronous plant. If these issues can be successfully resolved by amending the standards, there is no reason to define a new class of plant for GFM inverters in the NER, which would require consideration of the use of each defined term beyond the Chapter 5 access standards.

Options

The options considered to address identified issues were:

1. Do nothing
2. Redefine synchronous units to include GFM inverters
3. Redefine asynchronous units to exclude GFM inverters and define them separately.

AEMO does not see benefit in changing the definitions as recently made by the AEMC, considering the recommendations in this draft report designed to appropriately facilitate the connection of GFM inverters.

Recommendation

AEMO recommends Option 1.

Glossary

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
AAS	Automatic access standard
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
BESS	Battery energy storage system
CRI	Connections Reform Initiative
CUO	Continuous uninterrupted operation
DC	Direct current
FCAS	Frequency control ancillary service
GFL	Grid following
GFM	Grid forming
HVDC	High voltage direct current
IBR	Inverter-based resource
IESS Rule	National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021
IRP	Integrated Resource Provider
IRS	Integrated resource system
MAS	Minimum access standard
MFRT	Multiple fault ride through
MNSP	Market Network Service Provider
NAS	Negotiated access standard
NEM	National Electricity Market
NEO	National Electricity Objectives
NER	National Electricity Rules
NSP	Network Service Provider
OEM	Original equipment manufacturer
PFR	Primary frequency response
PMU	phasor measurement units
POD	Power oscillation dampers
PPC	power plant controller
pu	Per unit
Review	AEMO review of technical requirements for connection (pursuant to NER 5.2.6A)
review criteria	The criteria with which AEMO must have regard in assessing whether technical requirements should be amended, as prescribed in clause 5.2.6A(a)
REZ	Renewable Energy Zone
RoCoF	Rate of change of frequency
VSC	Voltage source convertor