RULE

Australian Energy Market Commission

RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (EFFICIENT REACTIVE CURRENT ACCESS STANDARDS FOR INVERTER-BASED RESOURCES) RULE 2023

PROPONENTS

Renewable Energy Revolution Pty Ltd
GE International Inc, Goldwind Australia Pty Ltd, Siemens Gamesa Renewable Energy Pty Ltd, Vestas Australia Wind Technology Pty Ltd

20 APRIL 2023

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Energy Ministers' Meeting (formerly the Council of Australian Governments Energy Council). We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the Energy Ministers' Meeting.

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SUMMARY

1 The Australian Energy Market Commission (AEMC) has made a more preferable final rule that lowers the reactive current fault-response capability that connecting inverter-based resources need to provide, and also clarifies several related terms. This will facilitate greater efficiency in the connection requirements of inverter-based resources (IBR), such as batteries, wind and solar, while also ensuring the security of the power system.

2 As the electricity sector decarbonises, significant investment in new generation is required. A substantial volume of this generation is forecast to be lower-cost, inverter-connected generation such as batteries, wind and solar. The more preferable final rule will lower costs to consumers by:

- increasing the efficiency of reactive current provision in the power system by ensuring it is tested against the needs of the power system
- allowing renewable energy generators to connect to the power system more quickly by streamlining the connections negotiations regarding the generators' ability to provide reactive current support in response to faults.

3 The more preferable final rule responds to two rule change requests, one from Renewable Energy Revolution Ltd and a second, from a consortium of wind turbine OEMs.[1]

4 The more preferable final rule revises the minimum access standard requirements for reactive current response from inverter-based generators in order to:

- lower the cost of these connections by reducing the minimum reactive current capability that asynchronous generators need to provide to a 'do no harm' standard
- align success factors of an adequate reactive current response to faults that are seen in practice, rather than those seen in controlled conditions
- simplify the negotiation of generator performance agreements by providing NSPs and AEMO added flexibility to agree on an alternate numeric standard if appropriate, and clarifying various Rule definitions.

5 The changes made by the more preferable final rule have been informed by extensive stakeholder consultation over two rounds of formal submissions, three technical working group meetings, and numerous individual conversations with wind turbine and battery original equipment manufacturers (OEMs), network service providers (NSPs), and AEMO. The work builds on work undertaken in the Connections Reform Initiative (CRI), and contributed to AEMO's technical access standards review.

Lowering the cost of inverter-based resource connections

6 The Commission considers the previous minimum access standard level for reactive current capability was too high, and was leading to investments in auxiliary equipment that were not tied to system security needs, as well as creating a risk of system instability.

1 This consortium comprised GE International, Goldwind Australia, Siemens Gamesa Renewable Energy and Vestas Australia.

7 The more preferable final rule addresses these issues by lowering the minimum access standard to a value that is greater than 0% of the maximum continuous current for a 1% change in voltage at the connection point during under- and over-voltage faults. The more preferable final rule also includes a definition for 'maximum continuous current' that enables maximum continuous current to be determined at:

- the connection point, where it will be based on the reactive current capability of the generating system, agreed under NER S5.2.5.1 at connection point normal voltage, or
- the unit terminals or a point between the unit terminals and the connection point., where a system-specific level of derating will be agreed between the connecting party, AEMO, and the NSP

8 This means that generators should not be absorbing reactive current during an under-voltage fault, and they should not be injecting reactive current during an over-voltage fault. Modelling undertaken to support this final determination showed that the standard was only not met in conditions where the plant was providing reactive current at its maximum output before the fault occurred [2]

9 While most generators will not need to invest in dynamic reactive current capability to meet the MAS, some generators such as large wind farms may need to. In these circumstances, insufficient reactive power capability may lead to voltage disturbances that spread, and have cascading effects on other generators' and loads' ability to stay connected.

10 Over time, the Commission expects that the more preferable final rule should lead to NSPs having to be more proactive in planning for and investing in dynamic reactive plant to ensure stable voltage levels during steady-state conditions and maintain adequate reactive power reserve margins to respond to faults. Meeting these obligations will require NSPs to establish the need for such investments as part of regulatory investment tests for transmission and distribution.

11 The Commission considers that the changes under the more preferable final rule are likely to be the most efficient way of delivering dynamic reactive power capability. Unlike generators, NSPs can consider the most cost-efficient solution to a much broader range of risks to voltage stability such as, load growth, and current and future generator connections. NSPs can also make investments to support complementary system security objectives, such as stable voltage waveforms, and frequency stability. In comparison, generators have narrow visibility of the current and future risks to system security on a local network and are not able to capitalise on economies of scale or scope.

Aligning reactive current response success factors to faults seen in practice

12 There were a range of issues with the previous reactive current response standards establishing when a response should start, how it should be controlled, and what options should be available to NSPs to ensure generator responses are adequately controlled. These

2 Aurecon, Advice on reactive current access standards, November 2022.

largely arise from the previous standards reflecting a requirement for adequate responses to clean, step-response voltage disturbances that are rarely seen in practice on the power system.

13 These issues are addressed in the more preferable final rule by removing the settling time requirement. The more preferable final rule also splits existing requirements designed to enable a fast response into two separate requirements:

- a new commencement time standard that requires a reactive current response to start within 40 milliseconds of a fault, and
- a longer rise time standard that requires reactive current responses to rise from 10% to 90% of its maximum in 80 ms.

14 These numeric standards were informed by OEM advice that the requirements help them design and tune their equipment before they are installed and commissioned and Aurecon's modelling of a hypothetical, Type 3, 500 MW wind farm.

Provide more flexibility to negotiate pragmatic standards that reflect practical challenges of generator and network operation

15 The rules should balance numeric precision, to allow generators to design, size and tune their equipment, with the flexibility to support pragmatic negotiations to accommodate 'edge' cases.

16 Edge cases reflect particular combinations of fault and plant operating conditions which may not be probable or present a significant system security risk — for example, when reactive current output is at its maximum level before a disturbance. Under these circumstances, generators may need to invest in auxiliary capability to provide more reactive current support, but this may not be efficient in all cases.

17 The more preferable final rules promotes the negotiation of pragmatic minimum access standards in these cases by allowing NSPs and AEMO to agree to the reactive current response:

- commencing at a connection point voltage level that is outside the numeric range in the rules
- that has a longer commencement time than the numeric value specified in the rules
- that has a longer rise time than the numeric value specified in the rules.

18 The more preferable final rule does not make any change to the definition of 'continuous uninterrupted operation' (CUO). This is a change from the draft determination, where we suggested amending this definition. Some stakeholders submitted that it was being interpreted to mean that the power system voltage fault response should be unchanged with the addition of a new plant. We note that this is not the intent of the rule, and that we only expect plant to be classified as not remaining in CUO if it causes a material degradation in the power system voltage fault response. NSPs and AEMO should acknowledge that the response will inherently change with the addition of new connected equipment, but that is only an issue where it varies in a materially negative way. Given this feedback, the final rule

does not amend this definition and insteads clarifies the intent through this determination.

19 The more preferable final rule also revises the 'adequately damped' standard and instead requires reactive current response to be 'adequately controlled'. The adequately damped standard, requires the fluctuation in the reactive current responses to decrease in magnitude over time. However, this is not always appropriate for more complex faults, and the revised standard will provide NSPs more flexibility to accept responses to such faults. The adequately controlled requirement is also supported by a second requirement that would allow NSPs to require that reactive current responses do not contribute to excessive voltage rise on undisturbed phases during unbalanced faults.

20 Submissions to the draft determination suggested that the final rule should clarify these terms but the Commission has determined not to, as doing so may inadvertently reduce the flexibility of connecting parties in making this change.

21 A summary of the key changes to policy positions that have been made in the final rule relative to the draft rule are provided in Table 1.

Table 1: **Summary of changes from draft to final rule**

ISSUE	DRAFT POSITION	FINAL POSITION	REASONS FOR CHANGE (IF ANY)
Reactive current capability standard	0%/% reduction in voltage or less than zero in exceptional cases agreed with NSPs and AEMO.	Positive contribution, greater than zero at the connection point.	Final rule sharpens the incentive to optimally tune inverters to provide the reactive current capability aligned to local electrical and fault conditions.
Point of compliance assessment	No change to current rule Default point of compliance assessment is at the connection point with flexibility to agree an alternate point of compliance at the unit terminals if needed.	No change.	
Active power recovery	Active power recovery to 95% of pre-fault level should	Addresses ambiguity associated with the use of 'stable' in the draft rule	Final rule reduces ambiguity regarding the reference point

ISSUE	DRAFT POSITION	FINAL POSITION	REASONS FOR CHANGE (IF ANY)
	take place after ***stable*** recovery of voltage levels to between 90 – 110% of normal voltage at the connection point.	and replacing it with the requirement that active power recovery commence when voltage '***remains'*** between 90 – 110% of connection point normal voltage.	from which the time taken for active power recovery is measured.
Definition of maximum continuous current	To be calculated based on the rated apparent power of the generating system, assessed at the connection point, which is agreed under S5.2.5.1.	Adds flexibility to the definition by allowing maximum continuous current to be calculated using an alternate level of apparent power if compliance is assessed at the unit terminals or another location within the generating system.	Final rule provides flexibility in the definition consistent with NER cl. S5.2.5.5(u)(2) that allows compliance point to be shifted from point of connection.
Definition of continuous uninterrupted operation	Part (d) of the definition of CUO changed to not exacerbating or prolonging the disturbance **such that it would result** ~~or cause a~~ subsequent disturbance for other **generating systems** ~~connected plant~~, except as required or permitted by its performance standards	Maintain existing rule.	Stakeholders noted that there was significant ambiguity regarding the draft rule position and this did not resolve the core issue associated with NSPs' current strict interpretation of CUO.
Voltage commencement threshold	Reactive current response can start at any point in the range 80 – 120% of the connection point normal voltage.	Drafting amended to maintain existing rule flexibility that allows reactive current response outside of the 80 – 120% range to be agreed on a case-by-case basis with NSP and AEMO	Final rule addresses an inadvertent error in the draft rule.

ISSUE	DRAFT POSITION	FINAL POSITION	REASONS FOR CHANGE (IF ANY)
		agreement. No change to the draft numeric range position defining when reactive current responses should start.	
Rise, settling, and commencement time	Settling time requirement deleted Rise time requirement doubled from 40 ms to 80 ms New commencement time requirement introduced	No change from draft rule.	

Source: AEMC

Implementation

22 In summary, the more preferable final rule has the following commencement dates:

- Schedule 1, which introduces the new reactive current minimum access standard in the NER, will commence on 27 April 2023
- Schedule 2, which makes amendments to the NER following the commencement of the *National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021 No. 13*, will commence on 3 June 2024, and
- Schedule 3, which includes transitional provisions (as described in section 1.1), will commence on 27 April 2023.

23 In effect, this means that the updated standards will commence one week after the publication of this determination. AEMO and NSPs will receive a 30 business-day extension to relevant connection process timeframes, for three months after the publication of this determination. These timeframes have been bought forward from those set out in the draft rule in response to feedback from stakeholders.

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1 THE COMMISSION HAS MADE A FINAL DETERMINATION

This final determination is to make a more preferable final rule in response to two rule change requests submitted by Renewable Energy Revolution (RER) Pty Ltd and a consortium of wind turbine original equipment manufacturers comprising GE International Inc, Siemens Gamesa Renewable Energy Pty Ltd, Goldwind Australia Ltd and Vestas Australia Wind Technology Pty Ltd (hereafter known as 'wind turbine original equipment manufacturers (OEMs)'.

The AEMC consolidated the two rule change proposals on 26 May 2022 as they both recommended changes to the minimum access standards that set out how much reactive current capability asynchronous generators need to provide after a fault.[3] The rule change proposal from the wind turbine OEMs had three objectives:

- To reduce the minimum reactive current response capability that generators need to provide following a contingency event, to one that better reflects local power system needs and reduces the risk of investment duplication on the network and generator sides.
- To relax the response characteristic requirements which are difficult to co-optimise with the capability requirement, especially for large wind farms.
- To provide clarifications on the definition of maximum continuous current and continuous uninterrupted operation.

RER's proposal focused on changing both the minimum and automatic reactive current injection standards to account for local reactance to resistance (X/R) ratios. RER noted that this revision would account for the contribution that the active current response makes to help support stable voltage levels, especially in networks characterised by low X/R ratios.

The rule making process was informed by collaboration with AEMO, input from the OEMs, NSPs, generation project developers, in individual discussions and across three technical working group meetings, as well as through two formal opportunities for feedback on the consultation paper and draft determination. Further detail on the rule making process is included in Appendix A.

1.1 What does the more preferable final rule do?

The Commission's more preferable final rule is attached to and published with this final rule determination. The key elements of the more preferable final rule are summarised below and offer the following benefits:

1. Lower the cost of renewable generator connections by allowing generators to avoid the cost of auxiliary dynamic reactive current capability where those investments deliver little to no system security benefits.

3 There are two components of AC electrical power, active power that does actual work, (i.e. provides heat, light and motion), and reactive power that enables the transport of electrical current. Fast reactive power response to severe under-voltages and over-voltages during contingency events helps to mitigate the impact of the contingency event on the power system and maintain stability.

2. Create stronger incentives over time for more scale-efficient provision of reactive current and complementary system security capabilities by NSPs where network planners assess that capability to offer the greatest value for voltage and frequency stability outcomes.
3. Facilitate faster negotiation of connection agreements between project developers, NSPs and AEMO by providing clarifications arising from internal inconsistencies in these access standards and the absence of definitions.

The key features of the more preferable final rule include:

1. Reducing the minimum reactive current capability that asynchronous generators have to provide under clause S5.2.5.5(n)(1) of the NER from 2% of a generating system's maximum continuous current per 1% change in voltage to be greater than 0% per 1% change in voltage at the connection point.

The rules require generators to agree a level of reactive current capability provision that is between the automatic access standard and the minimum access standard. NSPs cannot agree to connect a generator to their network if they are not able to meet the minimum access standard.

The changes set out in the more preferable final rule provide more flexibility for generators and NSPs to negotiate an amount of reactive current capability that is aligned with the network characteristics of the connection site and the system security risk that the connecting generator presents, while also providing a clear benchmark to support negotiations. The more preferable final rule disallows any reactive current contributions below the pre-disturbance level. The draft rule, in comparison, allowed a reactive current contribution either equal to the pre-disturbance level (i.e. zero) or below the pre-disturbance level under exceptional circumstances, i.e. with the agreement of NSPs and AEMO. This was changed in response to NSP and AEMO concerns around accepting responses that could exacerbate faults, instead of supporting voltages.

The final rule promotes the National Electricity Objective (NEO) in a number of ways. First, they provide greater flexibility in negotiations on the amount of reactive current capability that generators need to provide to respond to faults. This means that the access standard should lower the cost of new inverter-based generation connections compared to the status quo by not requiring investment in auxiliary reactive equipment that is not tied to specific system security outcomes. Instead, the standard should allow more explicitly for the inverter-based resources themselves to be harnessed to provide adequately controlled reactive fault response capability (see section 3.2).

Second, the more preferable final rule also lowers the reactive current capability standard, which will likely lead to the outcome of NSPs being more proactive in the delivery of dynamic reactive current capability (see section 3.1), using the regulatory planning and investment framework to facilitate this. This will drive greater efficiency in the delivery of reactive current capability over time by recognising that NSPs have a broader view of the risks presented by current and prospective changes in the profile and growth of load and generator connections in their network. Taking these matters into account, NSPs have a better view to design, size and site dynamic reactive current control equipment that manages risk to voltage and frequency stability in a scale-efficient way.

Both of the impacts set out above should result in lower costs to consumers. Connecting parties will have more flexibility to meet the access standards relating to reactive current, meaning that if there is scope to reduce costs they can, which will ultimately be passed through to consumers. Similarly, encouraging NSPs to think about the most cost effective way to maintain reactive current in the system will also benefit consumers.

In practice, the greater than 0% standard set out in the more preferable final rule will require generators to ensure that they are:

- providing a non-zero level of reactive current at the connection point
- not absorbing reactive current during an undervoltage fault, and
- not injecting reactive current during an overvoltage fault.

The more preferable final rule therefore effectively sets a 'do no harm' standard under the most onerous fault conditions.

The key themes in stakeholder feedback that support this change are summarised below in section 1.2.

2. Keep the reactive current capability minimum access standard at the connection point

The more preferable final rule maintains the current approach — and that of the draft rule — to have the reactive current minimum access standard assessed at the connection point. This ensures consistency with other standards and obligations on the NSP, and aligns with the point of handover or responsibility between the generator and the NSP. As was already possible under the existing rules, an alternate point of assessment between the unit terminals and connection point can be agreed with the proponent, where the NSP and AEMO agree. Such an approach should minimise costs to consumers.

This aspect was considered since the rule change proposal from the consortium of wind turbine OEMs recommended that the rules define that compliance with the reactive current capability standard be assessed at the generator unit terminals instead of the connection point (see Section 2.1 for more detail).

3. Relax the requirements under clause S5.2.5.5(o) of the NER for how quickly the response should rise to ensure a stable response and establish a commencement time standard to incentivise a fast response

The more preferable final rule maintains the draft rule's position on how quickly a response should commence, rise, and be controlled. This will incentivise a fast and stable response to voltage faults by specifying that the access standards require asynchronous generators' responses to:

- Rise from 10% to 90% of its maximum within 80 milliseconds, amended from the current 40 ms requirement.
- Commence within 40 milliseconds of the *response initiating condition* that is agreed between the NSP, AEMO, and the connecting project proponent.

The more preferable final rule also provides flexibility for an NSP and AEMO to agree on another commencement or rise time with the project proponent if that is more appropriate for the connecting location.

It also addresses a range of issues with existing arrangements:

- The current rise time standard, which is the same as the automatic access standard, may not be achievable under all fault conditions, especially unbalanced faults. The standard in the more preferable final rule will be achievable under a much broader range of fault conditions.
- Settling time is not a reliable measure of the adequacy of a reactive current response to a fault, because it was premised on the most onerous types of faults having a step response, which is not true in practice. The more preferable final rule deletes this requirement.
- The duration of a reactive current response to a fault is not a knowable quantity, a priori. Therefore, the final rule deletes the distinction in the definition of response characteristics depending on whether the response is longer or shorter than 2 seconds.
- The 'adequately damped' requirement is replaced with 'adequately controlled', to provide NSPs additional flexibility and acknowledge that some acceptable responses do not meet the engineering definition of 'adequately damped'.

4. Clarify in clause S5.2.5.5(n)(2) that voltage has to recover to remain between 90% and 110% normal levels before active power at the connection point should recover to its pre-fault level

The more preferable final rule requires voltage to recover to remain between 90% and 110% of the normal voltage before active power recovers to 95% of its pre-fault level. This is a slight change to the draft rule, which required voltages to be 'stable' in the voltage range before active power recovery. AEMO noted that stable was somewhat ambiguous, and proposed requiring voltages to 'remain' in the voltage range instead.[4] The Commission considers 'remain' to be less ambiguous than 'stable' and has included this change in the final rule.

This is a change to the former rules which required active power to recover to 95% of its pre-fault level as soon as the fault clears. This change clarifies that a unit's reactive response should be prioritised over its active response until voltages have recovered to close to normal levels. If the voltage is depressed, then the generator unit terminals may still be required to inject reactive current into the connection point to support stable voltage levels. Due to the relationship between voltage and active power, it is physically impossible for active power to completely recover while voltages are still depressed. The change in the more preferable final rule addresses this concern by clarifying that active power only has to recover once voltages have.

The more preferable final rule also makes it clear that the requirement for active power recovery in the NER should also be subject to other considerations including whether active

4 AEMO, submission to the draft determination, p. 5

power recovery would support or exacerbate other frequency disturbances that may be taking place at the same time by linking the requirement to NER cl. S5.2.5.11.

5. Provide for more technology-neutral access arrangements to cover the capability of grid-forming inverters that respond continuously to voltage disturbances

Grid-forming inverters (GFI) seek to mimic the behaviour of governors on synchronous machines. This means that they are continuously controlling reactive current to ensure voltages at the connection point remain stable, whenever there is a deviation of voltage levels from 100% of the normal voltage. However, the rules prior to this determination required grid-forming inverters to start their response within a fixed threshold for undervoltage faults in the range between 80% and 90%, or for overvoltage faults in the range of 110% and 120% of the connection point normal voltage.

The more preferable final rule allows NSPs and project proponents to agree on a broader range of connection point voltage triggers. This would be down to an undervoltage trigger of 80% or up to an overvoltage trigger of 120% of the connection point normal voltage. The flexibility to agree on triggers outside of this range where the NSP and AEMO deem to be acceptable remains, as was possible under the status quo. This represents a slight change from the draft rule, which did not allow for triggers outside the prescribed ranges to be agreed. GridWise and Transgrid noted that this was possible under the original rules, and removing it would limit the flexibility available to proponents, NSPs, and AEMO.[5] The Commission considers that there is minimal risk to power system security posed by the additional flexibility as agreement must be sought from both the NSP and AEMO, and as such has included it in the final rule.

6. Provide clarity that that generator control systems should ensure that their response prevents excessive voltage rise on unfaulted phases

The more preferable final rule maintains the draft rules position on voltage rise on unfaulted phases and requires asynchronous generators:

- To ensure that their response is controlled such that there is no excessive voltage rise on phases unaffected by faults during unbalanced fault conditions.
- To agree the maximum reactive current contribution in each phase with NSPs and AEMO and record this in the connection agreement.

The more preferable final rule has made this change noting that most faults are unbalanced. This change also allows NSPs to request changes to control system design and tuning to ensure that they are responding appropriately to unbalanced faults.

7. Define 'maximum continuous current' in Chapter 10 of the NER, with reference to the rated active power and power factor ratings defined in S5.2.5.1

The rules did not define prior to this determination 'maximum continuous current' of a generating system. However, clarity of application is important. Therefore, the more

5 Submissions to the draft determination: Gridwise, p. 2; Transgrid, p. 4

preferable final rule builds on the position of the draft rule and includes a definition of 'maximum continuous current', which can be assessed at either:

- the connection point, as was the case in the draft rule, where it would correspond to the largest amount of apparent power required by the generating system's performance standard under S5.2.5.1, at the normal voltage, or
- the unit terminals or a point between the unit terminals and the connection point, which provides further clarification over the draft rule, where it would be as agreed by the Network Service Provider for the transmission system or distribution system to which the generating system is connected and recorded in the connection agreement.

8. Maintain the existing 'continuous uninterrupted operation' definition

The final rule maintains the existing definition of 'continuous uninterrupted operation' (CUO).[6] This differs from the draft rule's position that looked to provide clarification that the power system's voltage response following a fault to remain the same with or without the project, an issue raised in the OEM rule change request. In responding to the draft determination, AEMO expressed discomfort with the draft determination's definition limiting their ability to decline plant whose response exacerbated the disturbance in a way that didn't affect other plant. This feedback was discussed with stakeholders one on one between the draft and final. Following these discussions, the Commission considers that the issue raised in the rule change request is one of interpretation, rather than the drafting.

Therefore, the final rule is to make no change from the existing definition of CUO (i.e. it does not adopt the draft rule wording or AEMO's alternative wording). The determination

makes clear that the definition of CUO should be interpreted in a way that acknowledges that the connection of new plant to the power system will inherently change the fault-response voltage characteristics of the system. However, this is only an issue if the changes represent a material degradation.

9. Maintain independence of reactive current minimum access standards from X/R ratio

Consistent with OEMs, NSPs,[7] and project developers[8] desire for the rules to provide more negotiation flexibility, the more preferable final rule maintains the draft rule's position and does not accept RER's proposal to link the maximum reactive current capability that inverter-based resources provide to local X/R ratio. The proposal noted that at low X/R ratios less reactive power is required to influence a given change in connection point voltage levels. However, the proposed change would be too restrictive as Windlab noted that most faults tend to have a high X/R ratio, because high voltage transmission lines and transformers lie between the fault and the generating unit terminals. In these settings, active power has a limited influence on voltage levels, and only reactive power is needed. No further feedback on this matter was received in response to the draft determination.

6 Chapter 10, Glossary, of the NER.

7 Submissions to the Consultation Paper: TasNetworks, p. 3; Energy Queensland, p. 8

8 Windlab, submission to Consultation Paper, p. 2

10. Clarifies the interaction of the more preferable final rule with the IESS final rule

On 2 December 2021, the AEMC made the *National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021 No. 13* (**IESS Rule)**[9]. The IESS Rule commences on 3 June 2024 and amends Schedule 5.2 of the NER.

The more preferable final rule maintains the position of the draft rule and clarifies that the amendments made by the IESS Rule to Schedule 5.2, which participants can connect under presently, will continue to apply, as amended by the more preferable final rule.

11. Provides clarity on the implementation of the more preferable final rule

The final rule commences earlier than the draft rule proposed to. In responding to the draft determination, GridWise and the CEC noted that they consider the rule should commence as soon as practicable and could commence earlier than the 10 weeks set out in the draft determination. Following consultation with NSPs and ENA on this feedback, the Commission has determined that the final rule will commence one week after the publication of this determination. AEMO and NSPs will receive a 30 business-day extension to relevant connection process timeframes. This decision balances stakeholder desire for the rule to commence as soon as possible with the need for NSPs and AEMO to get across the new rule.

Schedule 3 of the more preferable final rule includes transitional provisions that commence on 27 April 2023. These provisions:

- Enable persons that have:
  - submitted a connection enquiry but not yet submitted an application to connect; or
  - submitted an application to connect but not received an offer to connect,

  to proceed with determining their access standards under the new clause S5.2.5.5, rather than the existing reactive current minimum access standard.
- Provide AEMO and NSPs with a 30 business-day extension to certain time frames during the connection process, for example, in clauses 5.3.3(b) and (b1), so that they can assess the impact of the new minimum access standard. This extension will only apply for a 3 month period.

1.2 How did stakeholder feedback shape our decision?

The AEMC prioritised the rule change requests from RER and the consortium of wind turbine OEMs after the Connections Reform Initiative's December 2021 Roadmap highlighted the urgency of addressing issues with assessing and demonstrating compliance with the reactive current standards in clause S5.2.5.5.

We received 12 stakeholder submissions to the consultation paper and a further 12 submissions to the draft determination

9 Further information on the IESS Rule can be found here

The Commission initiated this rule change on 26 May 2022 and invited formal stakeholder submissions through the publication of a consultation paper.[10] We received 12 submissions to the consultation paper, which are published on the rule change project website and a further 12 submissions to our draft determination.[11]

The following key themes were consistent in feedback to both of these processes:

- Most stakeholders considered that the level of capability required under the existing MAS is too high to achieve the optimal outcome in all locations of the network.[12] [13]Only a couple of stakeholders considered that the MAS did not need to be reduced.[14]
- There were divergent views on what the standard should be lowered to, with some stakeholders supporting 1%/%,[15] and others supporting 0%/%.
- Many stakeholders felt that the connection point is the most appropriate compliance point, with some noting that this is consistent with other access standards.[16] However, other stakeholders proposed moving the compliance point to the generating unit terminals with a smaller (or no) reduction in the standard level.[17] [18]
- There was universal acknowledgement that there are practical difficulties with the response timing elements of the standard, with many noting that they do not correlate with any specific power system need.[19] Several solutions were proposed including maintaining the rise and settling time metrics with higher values,[20] or moving and defining new metrics .[21] [22]
- There is a general desire to increase clarity of definitions and the plant behaviour that is expected, to ensure that all parties in the connection process have a shared understanding.[23]
- Some stakeholders consider the balance of responsibility for supplying reactive capability in the power system should be shifted toward NSPs.[24]

10 AEMC, Efficient reactive current access standards for inverter-based resources, Consultation paper, 26 May 2022.

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

12 Submissions to the consultation paper: Clean Energy Council, p. 2; ACEN, p. 2; AEMO, pp. 6-7; Windlab, pp. 3-5; Tesla, p. 4; NeoGen, p. 2; TasNetworks, p. 2

13 Submissions to the draft determination: Clean Energy Council, p. 1, Goldwind Australia, p. 1, AEMO, p. 2, TransGrid, p. 2, TasNetworks, p. 2, Tesla, p.1, APDEngineering, p.1, Gridmo, p. 2, Powerlink, p.1.

14 Submissions to the consultation paper: Public Interest Advocacy Centre, p. 1; Ergon and Energex, p. 2.

15 Submissions to the draft determination: AEMO, , pp. 2-3, Transgrid, p. 3, TasNetworks, p. 2

16 Submissions to the consultation paper: Ergon and Energex, p. 4; AEMO, p. 7; Public Interest Advocacy Centre

17 Submissions to the consultation paper: ACEN, p. 2; Windlab pp. 3-4; Tesla p. 7; Neoen, p. 3; TasNetworks, p. 2

18 CEC submission to draft determination, p. 1.

19 Submissions to the draft determination: Gridwise energy solutions, p. 3, AEMO pp. 5-6, CEC, p. 1.

20 Submissions to the consultation paper: Ergon and Energes, p. 7; Clean Energy Council, p. 2; Windlab, p. 1

21 Submissions to the consultation paper: AEMO, pp. 4-6; Tesla, p. 8; Neoen, p. 5

22 CEC submission to draft determination, p. 2.

23 Submissions to the draft determination: APD Engineering, p. 3, Gridmo, p. 2, TransGrid, p. 3, AEMO, pp. 4-6, Gridwise energy solutions, pp. 2-3, CEC, p. 2..

24 Submissions to the consultation paper: ACEN, p. 2; Windlab, p. 3; Tesla, p. 5; Neoen, p. 2;

1.2.1 The more preferable final rule has been informed by independent technical analysis

The Commission also engaged Aurecon to provide technical advice on matters raised by the rule change request to support our understanding of:

- how much reactive current capability is appropriate for a given location?
- the factors that are likely to reflect the characteristics of an adequate reactive current response to a disturbance?
- the capability of non-wind turbine inverter-based technologies to meet the current and a revised minimum response standard.

Aurecon recommended a complete reformulation of the reactive current capability standard to a standard based on total current. It considered the proposal would ensure responses are easier to measure and better aligned to the ideal response to unbalanced faults. While there was some technical attraction to this proposal, OEMs and project-developers noted that negotiating a total current standard would make tuning control systems more challenging and create uncertainty for NSPs regarding how much total current is appropriate for a given type of fault in a particular location (see appendix D for further detail).

1.2.2 The more preferable final rule has been informed by extensive stakeholder collaboration

The Commission's final determination has been informed by extensive collaboration with AEMO, CRI representatives and input from industry across the rule change process. Further, the AEMC has conducted, a number of one-on-one conversations after submissions to the draft determination closed on issues raised in submissions with Tesla, AEMO, Powerlink, Transgrid, TasNetworks, Kate Summers and Keith Frearson, Bo Yin, APD Engineering, Gridmo, Goldwind, Gridwise Energy Solutuions, the Energy Networks Association and 5 of its members, and a workshop with 28 CEC members on 30 March 2023.

The Commission's views on how to set the reactive current capability standard and the definition of response characteristics were also supported by the CRI publishing its consolidated views on 6 July 2022.[25]

The technical complexity of this rule change led the establishment of a technical working group

The technical working group (TWG) was comprised of the stakeholders who made submissions to our consultation paper.[26] The three technical working group meetings we held with stakeholders helped the Commission understand stakeholders' views on:

- Principles that should govern the design and minimum access standard for an appropriate reactive current response to a voltage disturbance.

25 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022.

26 These meetings were attended by representatives from: GE International Inc., Tesla, Siemens Gamesa Renewable Energy, Vestas Australia, Windlab, Neoen, Clean Energy Council, ACEN Australia, Huawei, Gridwise Energy Solutions, ElectraNet, TransGrid, Powerlink, AEMO, the Connections Reform Initiative, TasNetworks, Energy Queensland, Yin Bo Consultancy.

- How Aurecon's PSCAD modelling[27] could support the Commission's assessment of the level at which the standard should be set and how response characteristics could be formulated to incentivise a fast, stable reactive current response to stabilise voltages as soon as practicable.
- Options for revising the reactive current capability standard and the definition of response characteristics to support a fast, stable and adequately controlled response
- Potential implications for networks who may have to bear a larger burden of planning for and providing reactive power if the minimum standard on asynchronous generators is lowered.
- Options for revising the reactive current capability standard, response characteristics, and other rule requirements that may improve rule transparency and clarity.

Several key themes arose in the TWG and subsequent one-on-one discussions

We heard the following key messages from stakeholders in both TWG and individual meetings, as well as through the submissions to the consultation paper and draft determination:

- Most stakeholders considered that setting a qualitative, principles based standard would create too much regulatory uncertainty as interpretation may be subject to how individual NSP connecting engineers applied their discretion
- OEMs and project-developers suggested that the rules should balance numeric precision in establishing a standard for reactive current capability and the control system response characteristics with flexibility to allow a more pragmatic standard where the risk of non-compliance is low or there may be other system security benefits
- AEMO and some NSPs were concerned that lowering the standard too far may lead to them being forced to accept tuned equipment (e.g. with generic OEM settings) and so recommended that the standard should be set at a level that sharpens incentives to optimally use the latent capability of inverter based plant
- Consultants to the renewables industry and the CEC recommended that Glossary definitions should be provided for any new terms that are introduced as part of this process to ensure negotiations do not become drawn out by disagreement on how connections will be assessed

More detail on the outcomes of the TWG meetings is provided in appendix A.2.2.

1.3 The more preferable final rule addresses one of the highest priority issues with current access standards

Australia is undergoing a transformational shift to net zero. A key feature of this transformation is the replacement of centralised thermal generation with decentralised inverter based plant such as renewables and battery storage. This requires a significant amount of capital investment in the NEM. Frictions in the existing connections framework

27 Power system computer aided design (PSCAD) modelling allows simulation and analysis of electrical circuits to allow users to understand the implications of input conditions on voltage and frequency stability.

have been observed to be a key challenge to achieving this objective. In light of concerns with delays and increasing complexity in connections to the NEM, in early 2021, AEMO and the Clean Energy Council (CEC) established the CRI. In the roadmap, the CRI noted that this rule change is consistent with the scope of the highest priority projects.

In addition, AEMO's access standards review is assessing the technical requirements in Schedules 5.2, 5.3 and 5.3a of the NER to assess whether those requirements should be amended. The draft recommendations for that review, propose to revise the automatic access standards so that it is better aligned with the changes made to the minimum access standard through this rule change.[28] The Commission notes that the automatic access standard was out of the scope of this rule change, but acknowledges that there are inconsistencies between the revised requirements in the minimum access standard and the unchanged automatic access standard. For example, a commencement time requirement was introduced in the minimum access standard, but does not exist in the automatic access standard. Similarly, the settling time requirement was removed from the minimum access standard, but remains a requirement in the automatic access standard. The Commission looks forward to continuing to work with AEMO on these issues.

28 For more information on AEMO's access standards review, see https://aemo.com.au/consultations/current-and-closed-consultations/aemo-review-of-technical-requirements-for-connection

2 WHY THE FINAL RULE WOULD CONTRIBUTE TO ACHIEVING THE ENERGY OBJECTIVES

This section of the paper outlines the:

- rule-making test the Commission has applied in deciding to make a more preferable rule including the ability of the Commission to do so
- ability for the Commission to make a differential electricity rule to apply in the Northern Territory, in certain circumstances.
- ways in which the more preferable final rule has best met the Commission's assessment criteria for this rule change and consequently the NEO

The Commission has made a more preferable final rule that promotes the long-term interests of consumers. This more preferable final rule is published alongside this final rule determination.

The Commission is satisfied that lowering the minimum amount of reactive current capability that asynchronous generators have to provide, combined with other changes to when and how quickly the response needs to start, how it should be controlled and how active power should recover after a fault will contribute to the achievement of the NEO. This should support system security and lower costs for voltage management over the long term. It will do so by recognising the important role of NSPs using the regulatory investment test process to identify and test options with stakeholders to ensure the delivery of scale and scope efficient ways of ensuring voltage is controlled to acceptable levels of fluctuation after contingency events.

2.1 The Commission's rule making tests

2.1.1 The rule change must contribute to achieving the NEO

Under the NEL, the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NEO.[29] This is the decision making framework that the Commission must apply, and has done so for this rule change.

The NEO is:[30]

> 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:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

See appendix B for more detail on the legal requirements for a decision.

29 Section 88 of the NEL.

30 Section 7 of the NEL.

2.1.2 Making a more preferable rule

Under s. 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

For this rule change proposal, the Commission has made a more preferable final rule. The reasons are summarised in section 2.3 below.

2.1.3 Making electricity rules in the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to modifications set out in regulations made under the Northern Territory legislation adopting the NEL.[31]

The more preferable final rule relates to parts of the NER that apply in the Northern Territory,[32] and the Commission has therefore assessed the more preferable final rule against additional elements required by the Northern Territory legislation:

- *Should the NEO test include the Northern Territory electricity systems?* Yes. For this rule change request, the Commission has determined that the reference to the "national electricity system" in the NEO includes the local electricity systems in the Northern Territory, as well as the national electricity system.
- *Should the more preferable final rule be different in the Northern Territory?* No. In making the more preferable final rule, the Commission has considered whether a uniform or differential rule should apply to the Northern Territory. The final rule determination is to make a uniform rule because S5.2.5.5 of the more preferable final rule will not apply in the Northern Territory in practice. Only the amendments made to Chapter 10 of the NER will apply, but will have no practical effect. As such, a differential rule will not better achieve the NEO in this instance.

See Appendix A for further information on these determinations.

2.2 Considering the more preferable final rule against the assessment criteria

The Commission has considered how the reactive current fault-response capability minimum access standards can provide sufficient locational flexibility to ensure reactive capability is provided efficiently across generators and NSPs.

The AEMC employed the following criteria in its assessment on whether the proposed approach or alternative options would, or were more likely to, contribute to the achievement of the NEO:

31 National Electricity (Northern Territory) (National Uniform Legislation) Act 2015 (NT Act). The regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modification) Regulations 2016.

32 Under the NT Act and its regulations, only certain parts of the NER have been adopted in the Northern Territory. The version of the NER that applies in the Northern Territory is available on the AEMC website at www.aemc.gov.au/regulation/energyrules/northern-territory-electricity-market-rules/current.

- **Promoting system security and reliability**: the Commission has assessed whether the reactive current capability and other related aspects of the access standards are set to promote power system security and reliability. If the standard is too loose, insufficient reactive capability may be provided by generators. If it is too tight, generators may be required to make investments that are otherwise not needed, increasing the total system cost. The Commission has sought to strike a balance between these two extremes when making the more preferable final rule.
- **Efficient cost and risk allocation**: the Commission has assessed whether the reactive current capability standard appropriately incentivises the allocation of costs of providing that capability and managing the risks to connection point voltages after faults. Costs should be allocated to parties who have the best means to manage and reduce those costs. This should ultimately result in lower whole-of-system costs that are passed on to consumers.
- **Transparency and simplicity**: the Commission has looked to this criterion to ensure connecting parties have clarity on their obligations, including how the rules can facilitate the efficient assessment of the capability expected from equipment, and to clarify internal inconsistencies between different elements of the rules.
- **Implementation costs:** the Commission has assessed whether the costs of implementing the revised access standards and any other, new obligations are outweighed by the benefits including, where possible, that individual stakeholder groups are not disproportionately impacted by implementation costs.

No stakeholders considered the above assessment criteria to be incomplete or inappropriate in their submissions to the consultation paper or draft determination. The stakeholders who did provide feedback on the proposed assessment criteria noted their agreement with them.[33]

2.2.1 The final rule ensures IBR are supporting power system voltages for system security

The more preferable final rule acknowledges that the amount of reactive current response capability required to ensure voltages stabilise as soon as possible after a fault is highly location dependent and influenced by a range of factors, including:[34]

- Fault location relative to the connection point
- Fault type (i.e. whether it affects all three phases of an AC electrical circuit and is balanced or only affects one or two phases and is unbalanced)
- Network characteristics such as topology, impedance, short-circuit ratio, and the reactance to resistance ratio (X/R)
- Load composition and how it is expected to change over time (e.g. falling minimum demand is having significant implications for voltage stability)
- Nearby sources of dynamic reactive current response and how much additional generation an area may be able to support.

33 Submissions to the Consultation Paper: Tesla, p. 4; Neoen, p. 1; Ergon & Energex, p. 2

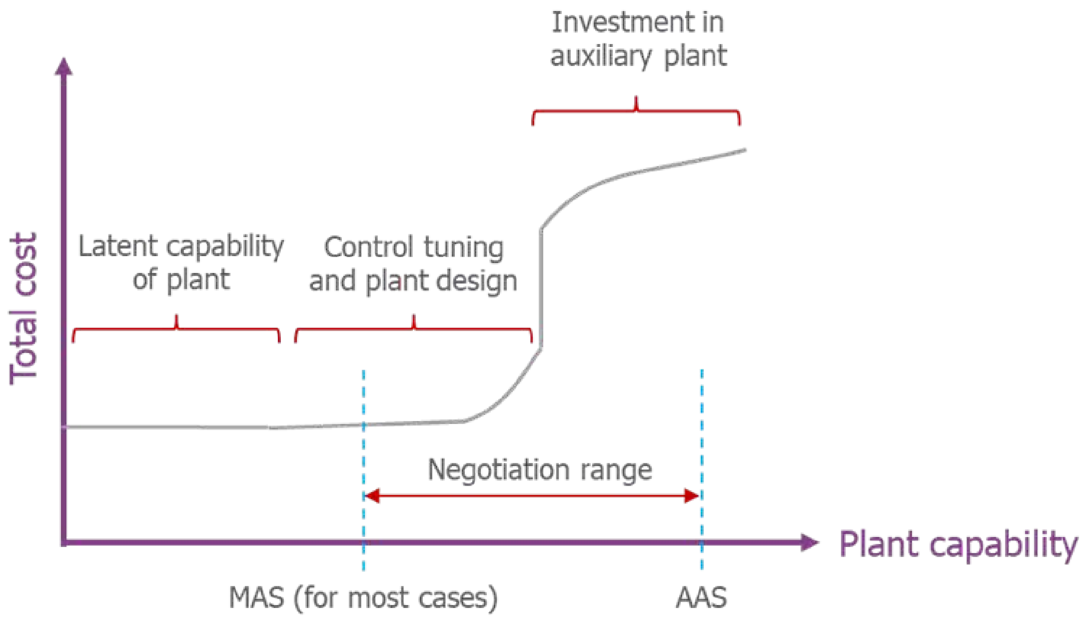
34 Aurecon, Advice on reactive current access standards, p. 18

In this context, the Commission recognised that the reactive current access standard in place at the time the rule change was considered was requiring generators to invest in a level of capability that was not calibrated to a specific system security need.

IBR have an inherent ability to provide a reactive current response to faults and OEMs accepted that the cost to generators of providing reactive power support is typically low, up to a point.

Figure 2.1 is a stylised plot of the costs connection proponents may face. It shows the low marginal cost of harnessing the latent capability of the plant, through control system tuning, optimising the design of the reticulation system, and other balance of plant, up to a point. However, beyond this level, the marginal cost of providing additional reactive current capability increases substantially. This is because it would require the installation of auxiliary plant, such as static synchronous compensators (STATCOMs) that can quickly inject or absorb reactive current to stabilise voltage levels near the point of generator connection.

Figure 2.1: Stylised illustration of the relationship between the cost of providing reactive current fault response capability



Source: AEMC

This illustration does not reflect the specific characteristics of each IBR and is likely to be more representative of the costs wind farms face. Wind farms are more likely to experience these cost characteristics as solar farms and BESS typically have much shorter internal reticulation systems, which do not attenuate the reactive current capability from the inverter to the connection point.

There was a broad consensus amongst generation project proponents, wind turbine OEMs, and NSPs that the level of the minimum access standards should be lowered.[35] However, there was disagreement on the exact level. AEMO's submission, reflecting NSPs' preferred position was to recommend a standard of 1% per % change in voltage.[36] A number of NSPs supported a standard aligned to what the CRI's technical paper recommended, namely that the rules require that the reactive current capability be set at a level that NSPs and generators agree, but be greater than 0%.[37] [38]

The more preferable final rule better balances the need to install well-tuned generating system that optimally uses inverter based plant's latent reactive current control and management capability, while avoiding unnecessary investments in auxiliary plant, where this is not necessarily tied to explicit system security needs. Setting the minimum reactive current capability standard at a level greater than zero should sharpen incentives to ensure that some capability is provided to alleviate fault conditions and ensure faster recovery of voltage levels.

Even if a plant is well-tuned, there may be other specific circumstances (e.g. for large wind farms in a weak area) where investments in auxiliary plant are necessary. In these cases, the absence of sufficient reactive fault response capability may lead to sustained voltage imbalance that leads to poorer power quality outcomes for nearby loads and increases the frequency of local unserved energy.

Consequently, we have determined that the management of voltage stability after disturbances is likely to be supported at the lowest cost by the MAS:

1. providing connecting parties (project proponents, NSPs and AEMO) more flexibility to agree a pragmatic standard that is aligned to locational voltage stability risks, especially where the project offers other or complementary system security benefits (e.g. for frequency management).
2. incentivising project generators to optimise the latent capability of IBR to support grid voltages during and after faults by providing more reactive current than the pre-disturbance level to faults.

2.2.2 The more preferable final rule promotes efficient allocation of risks and costs

The more preferable final rule recognises that existing NSP and AEMO planning processes create obligations on these parties to plan for and deliver reactive current capability in the medium term at least cost to address credible voltage stability risks through the regulatory investment test (RIT) cost benefit analysis process (see section 2.2.2).

In their submissions, Windlab, the Clean Energy Council (CEC) and a number of other stakeholders highlighted the risk that the system strength rule change may lead to NSPs and

35 CEC submission to draft determination, p. 2.

36 AEMO, submission to Consultation Paper, p. 7, AEMO, submission to Draft Determination, p. 2, Tasnetworks submission to draft determination, p. 2

37 Vysus Technical Note, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, Section 2.3, pp. 12-13

38 TransGrid submission to draft determination, p. 2

generators investing in the same type of infrastructure, designed to support connection point voltage levels.[39] Specifically, they noted the risk that maintaining the reactive current capability requirement at the current level, or not lowering it far enough, may lead to some network system strength investments being stranded. This could arise if generators choose to self-remediate the voltage stability impact of their connection on the network instead of purchasing system strength services from NSPs.

Under Schedule 5.1 of the NER, NSPs that are System Strength Service Providers (SSSP) may need to invest in equipment that also provides dynamic reactive support (e.g. synchronous condensers). However, it is likely that these NSP investments would be complementary to dynamic reactive capability and not substitutes.

The Commission has determined that the more relevant connection between NSP and generator obligations resides in NER Schedule 5.1. This Schedule requires NSPs to ensure that steady state voltage magnitude and variations in voltage magnitude are within a specified band,[40] and that voltage is controlled following the most severe credible contingency or any protected event by ensuring that an adequate reactive power margin is maintained at every connection point in a network.[41]

NSPs would typically address this need through the regulatory investment test process. This requires NSPs to establish the need for a particular network investment and whether that need will deliver net benefits to wholesale electricity market outcomes, or whether it will serve to help networks meet their obligations under NER Schedule 5.1. If it is the latter, and the AER accepts that there is a credible risk that NSPs may not meet their performance obligations, then the AER must approve the lowest cost solution to address the risk of non-compliance with network performance obligations.

AEMO through its Network Support and Control Ancillary Services (NSCAS) planning process may also identify gaps in reactive power capability to manage risks to system security and reliability performance benchmarks.[42] Gaps identified by AEMO often lead to transmission network service providers (TNSPs) investing in capability to address these gaps.[43] If TNSPs do not address the gaps, AEMO is able to tender for and procure that capacity directly.

Given these obligations, the more preferable final rule provides a wide negotiating remit for prospective generator-NSP negotiations to capture the cases where generator capability can be harnessed at relatively low marginal cost and/or manage significant credible risks, such as from particularly large wind farms. However, the core objective of the standard is not to require significant investments from generators that crowd out NSP investment where the latter offers the potential to achieve economies of scale and scope.

39 Submissions to the Consultation Paper: Windlab, pp. 6-7; ACEN Australia, p. 2; CEC, p. 2

40 NER Clause S5.1.4

41 NER Clause S5.1.8

42 AEMO 2020, Network support and control ancillary services description and quantity procedure, pp. 10-11

43 ACEN Australia submission to consultation paper, p. 2

2.2.3 The more preferable final rule promotes transparency and simplicity

It is important that connection proponents, NSPs and AEMO have a clear, shared understanding of the MAS requirements and how they would be measured and assessed. This is to ensure:

- The reactive current capability and the response characteristics standard are applied consistently for connection applications across jurisdictions.
- Proponents can tune their plant's reactive current response in a way that corresponds to the NSPs expectations in the first optimisation pass.
- Delays in settling connection agreements or AEMO registering a connection are not encountered by connecting parties due to divergent understandings of compliance approaches.

Additionally, this would help foster competition in the development of IBR projects, as the standards would be equally understood by both new entrants to the market, and established developers.

The OEMs' rule change request identified several elements of the reactive current MAS that they considered more clarity should be provided.[44] Through further discussion with NSPs, OEMs and generation project developers in the TWG, we have reaffirmed the areas that the rule change proponents proposed require furtehr clarity. We have provided clarity on the matters, as outlined below, to achieve the aforementioned goals.

How reactive and active current should be prioritised after a fault clears

The CRI considerered the rules to be unclear and inconsistent in outlining how and when reactive and active power response should occur following the clearance of a fault.[45] The Commission agreed with the CRI's assessment that the following two rules requirements may be in conflict:

1. That active power recovers to 95% of its pre-fault level immediately after the fault clears[46]
2. That reactive current injection be maintained until the connection point voltage recovers to between 90% and 110% of normal voltage[47]

There is inconsistency between the two objectives, as the voltage is not always within the 90% to 110% normal voltage range upon fault clearance. To stabilise voltages at an appropriate level, generators typically need to continue injecting or absorbing reactive power, even after the fault. So, for a generator's active power to recover to its pre-fault level, connection point voltages have to recover to within 10% of the normal voltage at the connection point.

44 GE International Inc., Goldwind Australia, Siemens Gamesa Renewable Energy, Vestas Australia; Reactive current response to disturbances (S5.2.5.5) Rule Change Proposal (ERC0329), pp. 10-12

45 Vysus Technical Note, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, pp. 10-11

46 This can be implied by NER Cl. S5.2.5.5(n)(2)

47 NER Cl. S5.2.5.5(f)(1)

To reflect this reality, provide clarity on how active and reactive power should be prioritised, the more preferable final rule clarifies that the time taken for active power recovery should be recorded from the last excursion of voltage outside the range between 90% and 110% of the normal connection point voltage. The draft rule wording introduced some ambiguity regarding the point in time from which the measurement of active power recovery should take place, by saying that voltages needed to be 'stable' in the 90% to 110% range. AEMO noted that 'stable' does not have a clear meaning and noted that it would be clearer if it was replaced with 'remain'. This change better satisfies the transparency and simplicity assessment criterion than the draft rule.[48]

The more preferable final rule has not changed the draft rule system obligations in relation to frequency disturbances[49] as a factor that should guide negotiations of how quickly and to where active power should recover to following a clearance of the fault.[50]

Reactive current responses should not lead to excessive voltage rise on unfaulted phases during unbalanced faults

The CRI noted that the rules could be clearer that connecting generators should avoid responses that result in excessive voltage rise on unfaulted phases.[51] The more preferable final rule codifies the requirement by specifying that generators' reactive current contribution does not contribute excessively to voltage rise on unfaulted phases during unbalanced faults.

The inclusion of this requirement supported by AEMO's submission to the consultation paper, and broadly supported by stakeholders in technical working group discussions. However, submissions to the draft determination from consultants who support the connections process, suggested that the Commission should provide a definition for what constitutes 'excessive voltage rise' on unfaulted phases.[52] The Commission has in this instance determined to not provide a definition as a narrowly cast definition may inadvertently limit the flexibility that NSPs need to ensure that existing practice is not restricted in unintended ways.

One possible way that this matter may be addressed could be through the development of NSP guidelines that could specify how they evaluate whether injection or absorption of reactive current into healthy phases is acceptable or otherwise. More discussion on issuers with the negotiation framework is provided in chapter 3.

The definition of '*maximum continuous current*'

The generating system's *maximum continuous current* is the base quantity that is used to determine the amount of reactive current capability it needs to provide. The wind turbine OEMs' proposed that the Commission should define *maximum continuous current* in the

48 AEMO submission to draft determination, p. 5

49 NER Cl. S5.2.5.11

50 Clause S5.2.5.5(n)(2)(ii) of the final rule

51 Vysus Technical Note, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, pp. 11-12

52 Submissions to the Draft Determination: Gridmo, p. 3, Gridwise Energy Solutions, pp.2-3.

rules, given it is not currently defined and stakeholders consider that no definition is creating ambiguity and confusion in the connections process.[53] [54] [55]

The Commission provided a definition in the draft rule that would result in all parties having a common understanding of *maximum continuous current* throughout the rule change process. However, several submissions to the draft determination noted that it did not provide, flexibility to calculate this value for a location other than the connection point.[56] The more preferable final rule addresses this discrepancy and the specific definition used, and the reasons for its selection are outlined in section 3.4.1.

Clarity in obligations relating to '*continuous uninterrupted operation*'

The more preferable final rule maintains the status quo definition of continuous uninterrupted operation (CUO) i.e. does not adopt the draft rule wording.

The draft rule proposed modifying part (d) of the definition to link remaining in CUO to 'not causing disturbances for other generators'.[57] This was done to address an issue raised in the OEM rule change request, that noted that some strict interpretations of the obligations imposed by the requirement to remain in *continuous uninterrupted operation* are creating perverse outcomes in the connection process.[58] They note that in some instances part (d) of this requirement has been interpreted to mean that the power system's voltage response following a fault should remain to remain the same in simulations, with or without the project.

AEMO was not supportive of this change, and considered that responses that materially exacerbate the fault are problematic, regardless of whether they cause a disturbance for another generator.[59]Powerlink suggested that the changes to CUO should follow the status quo in prohibiting adverse impacts to all connected plant as opposed to only generators.[60] The CEC suggested removing ambiguity from 'disturbance' by linking the definition to causing other generators to breach their performance standards where they otherwise wouldn't have.[61]

Following bilateral discussions with stakeholders on this issue post the draft determination, the Commission considers that the issue is one of interpretation. Therefore, the Commission has determined not to make any change to this definition i.e. retain the wording from the current rules.

53 GE International Inc., Goldwind Australia, Siemens Gamesa Renewable Energy, Vestas Australia; Reactive current response to disturbances (S5.2.5.5) Rule Change Proposal (ERC0329), pp. 20-21

54 Submissions to the Consultation Paper: CEC, p. 3; AEMO, pp. 7-10

55 Vysus Technical Note, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, pp. 9-10

56 Submissions to draft determination: Gridwise Energy Solutions, p. 3, APD Engineering, pp. 3-4, AEMO, p. 3, Powerlink, p. 1,

57 The status quo definition of CUO part (d) is: *In respect of a generating system or generating unit operating immediately prior to a power system disturbance: not exacerbating or prolonging the disturbance or causing a subsequent disturbance for other connected plant, except as required or permitted by its performance standards*

58 GE International Inc., Goldwind Australia, Siemens Gamesa Renewable Energy, Vestas Australia; Reactive current response to disturbances (S5.2.5.5) Rule Change Proposal (ERC0329), pp. 11-12

59 AEMO, submission to the draft determination, p. 5

60 Powerlink, submission to the draft determination, p. 1

61 CEC, submission to the draft determination, p. 2

The definition of CUO should be interpreted in a way that acknowledges that the connection of new plant to the power system will inherently change the fault-response voltage characteristics of the system. However, this is only an issue if the changes represent a material degradation.

For detail on the rationale for this change, see section 3.4.2.

2.2.4 Implementation considerations

Rule implementation time frame

The Commission considers that the more preferable final rule should commence as soon as possible to minimise any barriers to entry that may stem from the existing reactive current access standards. This view is supported by stakeholders. On that basis:

- Schedule 1 of the more preferable final rule, which will introduce the new reactive current minimum access standard in the NER, will commence on 27 April 2023.
- Schedule 3 of the more preferable final rule, which includes transitional provisions that deal with proponents that have lodged a connection enquiry or are in the connection process but have not received an offer to connect, and provides NSPs and AEMO a 30 business day extension for certain steps in the connection process, will commence on 27 April 2023.
- Schedule 2, which includes provisions to ensure the more preferable final rule continues to operate as intended after the commencement of the IESS Rule, commences after the IESS Rule on 3 June 2024.

Rule implementation costs

The Commission considers that any implementation costs associated with the more preferable final rule are likely to accrue to NSPs, and arise from NSPs having to take more responsibility in evaluating the potential implications of adopting a less stringent reactive current capability standard than it is possible to accept under existing arrangements. There may be some small costs to generators who would have to understand these new rules.

NSPs' capacity to interrogate whether a generator's latent capability to provide additional reactive current capability at a fairly low cost is dependent on the collective experience of their engineers in connecting those types of projects (e.g. large and complex wind farms). Investing in an appropriate amount of human resource capability to ensure generators provide a cost-efficient amount of reactive current capability will be critical.

Doing so would help NSPs ensure that:

1. they are able to critically interrogate plant design, including the circuit layout of the internal reticulation of system, and the placement of transformers to minimise losses from generator unit terminals to the connection point and
2. they can establish an understanding of the control systems capability of inverter based generators and how they should be tuned to ensure that they provide the optimal amount of reactive current capability to ensure appropriate responses to credible, severe faults.

The Commission has not quantified the costs of ensuring that NSPs have appropriate capability to manage the risk of generators providing less reactive current capability through poor quality equipment or poor tuning. However, we expect the costs of developing this capability to be low. Moreover, we expect that the benefits of the more preferable final rule, as set out above, in terms of having more flexibility and so lower cost flowing through to consumers, as well as minimising any delays to connection due to the former rules not being fit for purpose, would outweigh these costs.

2.3 Why the more preferable final rule better meets the NEO than the rules proposed by the proponents

For the reasons outlined above and explored in further detail across the elements of chapter 3, the Commission has made a more preferable final rule as it will better meet the NEO. Chapter 3 of this final determination provides further detail on why we have made a more preferable final rule on the following elements of the rule:

1. Lowering the reactive current capability standard but maintaining compliance assessment at the connection point (see section 3.1) instead of shifting the assessment of compliance for this standard to the generator unit terminals as recommended by the wind turbine OEMs or tying the capability standards to locational reactance to resistance (X/R) ratios as recommended by RER. The assessment of this capability will be based on the maximum rated apparent power of the generating system instead of each generating unit as the wind turbine OEMs proposed, and connection point normal voltages. The more preferable final rule should help ensure consistent assessment of reactive capability across different inverter-based generation technologies and connection locations while maintaining existing flexibility in the rule for the reactive contribution to be assessed at the unit terminals.
2. Establishing a new commencement time standard that can be assessed at the unit terminals or connection point, a longer rise time standard assessed at the connection point and deleting the settling time requirement to ensure a fast and stable response (see section 3.2) for faults seen in practice, rather than in controlled test conditions. The more preferable final rule better meets the NEO compared to the wind turbine OEMs' proposal to raise the rise and settling time numeric standards and assess those standards at the unit terminals.

3 ELEMENTS OF THE FINAL RULE

A description of the more preferable final rule is set out in chapter 1. This chapter provides additional details on the elements of the more preferable final rule.

The more preferable final rule includes the following key elements:

- **The minimum required reactive current capability for asynchronous generators in clause S5.2.5.5(n)(1) has been lowered to require generators to provide a non-zero level of reactive current capability.**

  The more preferable final rule ensures that generators are providing some capability, and are not permitted to absorb, or inject reactive current during an undervoltage fault or overvoltage fault respectively.

- **The response characteristics in clause S5.2.5.5(o) have been relaxed to incentivise a fast and adequately controlled reactive current response to stabilise connection point voltages as soon as practicable.**

  The more preferable final rule establishes a commencement time standard that creates an incentive for reactive current responses to start as soon as practicable, and a revised rise time requirement to ensure that reactive current rises quickly enough to enable voltages to recover as soon as practicable. The previous rise time standard incentivised reactive current responses to increase at a pace that may lead to connection point voltage instability. The more preferable final rule also deletes the existing settling time requirement and replaces the 'adequately damped' requirement with a requirement for the response to be 'adequately controlled'.

- **Generation project proponents and NSPs can negotiate pragmatic control system responses to enable grid-forming inverters to connect more easily. It is also clarified that active power recovery will only need to start after voltages remain in the range 90 - 110% of POC normal voltage and will allow NSPs to ensure that generators provide an adequately controlled response to unbalanced faults.**

  The more preferable final rule allows connecting generators to commence their reactive current response at any point in a range +/- 20% of the connection point normal voltage or at a different connection point voltage level, as may be agreed with NSPs and AEMO. This will allow GFI to connect more easily than under current arrangements as they respond continuously to voltage disturbances like synchronous machines.

  The more preferable final rule also allows generators to measure the time taken for active power recovery only when voltage levels are in the range 90 - 110% of connection point normal voltage. If there is a voltage excursion outside the 90 - 110% range for any length of time, the timer recording how long active power recovery should take is reset. The final rule also codifies existing arrangements that see NSPs require reactive current responses to mitigate excessive voltage rise on unfaulted phases of an electrical fault.

- **Clarity is provided on the definition of 'maximum continuous current' but not on CUO or reactive current calculation**

The more preferable final rule makes the connection process more transparent and straightforward. It does this, by tying the definition of 'maximum continuous current' (MCC) to the performance that is agreed for normal operation, under NER Schedule 5.2.5.1, if compliance assessment is undertaken at the connection point. If compliance is assessed at a location other than the connection point, then the method for MCC calculation, including any derating factors would need to be agreed between generators, NSPs and AEMO, on a case-by-case basis.

By comparison, the final rule does not change the definition of CUO from the status quo as the Commission considers that the issues raised by the wind OEMs are issues of interpretation. This is discussed in more detail in section 3.4.2. Similarly, the method to calculate reactive current is not defined under the more preferable final rule, due to the complexity involved in doing so, but the Commission expects NSPs to provide guidance on how it should be calculated for connection assessments.

3.1 Lowering the minimum capability requirement to an agreed value greater than (but not equal to) zero should provide more scope for balancing costs to generators and the system needs

Clause S5.2.5.5(n) of the more preferable final rule requires generators to provide the capability to inject or absorb more reactive current, than the pre-disturbance level, after a fault initiating condition and voltage trigger that is agreed with NSPs and recorded in the connection agreement.

This differs from the draft rule that would have allowed NSPs and AEMO to agree to a capability of zero or less than zero %/% (i.e. an amount of reactive current below the pre-disturbance level) on a case-by-case basis, where there is no harm to system security. The change is in response to NSP and AEMO concerns around accepting responses that could exacerbate faults, instead of supporting voltages.[62] The Commission considers that the final position of requiring some contribution to voltage support achieves an appropriate balance between maintaining power system security and flexibility.

The principles that the Commission has followed for the development of the final MAS have not changed from the draft position, as they were broadly supported by stakeholders, notwithstanding broader issues with the connection negotiations framework that some stakeholders raised. The two principles are, to ensure that connecting IBR:

- make their latent reactive current provision capability available to the power system, in a well-tuned manner; and,
- are not degrading the network through their connection.

Substantial stakeholder input has contributed to the Commission's decision as to what minimum reactive current capability will provide the best outcome for consumers. Technical advice from Aurecon has also formed part of the basis for this decision.

62 Submissions to the draft determination: AEMO pp. 2-3, TasNetworks p. 2, Transgrid p. 3

3.1.1 Stakeholders agree that the existing standard can lead to inefficient provision of reactive current capability

The existing minimum reactive current capability access standard requires connecting IBR to provide the capability to inject or absorb reactive current of 2 %/% for under and over-voltage events, respectively.

The OEMs' rule change stated that the level of reactive current capability required under the standard applying at the time the rule change request was considered is too high. They considered that this is resulting in increased costs to consumers, and on occasion, poorer power system security outcomes in the NEM.

The OEM's noted that the 2 %/% requirement at the connection point can be difficult to meet for projects with large reticulation systems. They noted that this can be worked around by tuning the unit controllers with high reactive current gain settings. However, this may result in voltage rising to normal levels at the unit terminals before the fault has cleared, causing the unit to leave low-voltage ride-through (LVRT) mode. Following the withdrawal of voltage support, the voltage drops and the unit re-enters LVRT mode, with the consequence of this oscillation between modes leading to instability on the power system.[63] Where projects cannot meet the 2 %/% requirement in a stable manner, from the response of their units alone, the installation of reactive plant such as SVCs or STATCOMs at or near the connection point is required to meet the standard.[64]

Many stakeholders in submissions to the consultation paper supported this view, considering a MAS of 2 %/%, measured at the connection point, to be inappropriately high. Stakeholders noted that this is creating two issues:

- instability arising from high gains used in plant controllers, to achieve the required response magnitude[65] [66]
- the installation of auxiliary reactive plant that is not assessed against any specific system need[67]

Two stakeholders did not consider that lowering the reactive current MAS was necessary or of benefit to consumers:

- PIAC considered that the MAS should not be lowered to zero %/% on the basis that it would shift the burden of providing voltage stability services to networks, creating additional costs for consumers in doing so.[68]
- Ergon / Energex noted that in their experience all connecting IBR have been able to meet the existing MAS by optimising their reticulation and balance of plant design, and thus

63 GE International Inc., Goldwind Australia, Siemens Gamesa Renewable Energy, Vestas Australia, National Electricity Rule Change Proposal Reactive current response to disturbances (S5.2.5.5), pp. 8-9

64 GE International Inc., Goldwind Australia, Siemens Gamesa Renewable Energy, Vestas Australia, National Electricity Rule Change Proposal Reactive current response to disturbances (S5.2.5.5), pp. 8-9

65 submissions to the consultation paper: AEMO, p. 3; Windlab, p. 3

66 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, p. 8

67 submissions to the consultation paper: Windlab, p. 3; ACEN, p. 2

68 Public Interest Advocacy Centre, submission to the Consultation Paper, p. 1

there isn't a need to reduce the MAS.[69] They acknowledged, however, that large injections of reactive current can result in instability in weak areas of the grid.[70]

3.1.2 A non-zero minimum access standard combined with the existing negotiating framework will provide NSPs with flexibility and the ability to ensure connecting plant is well-designed and tuned

No stakeholder raised any issues with lowering the minimum reactive current capability standard in draft determination submissions.[71]

Stakeholders had mixed views on the level that the standard should be lowered to

While many project-developer stakeholders support lowering the standard to 0 %/%, NSPs and AEMO were less supportive in their submissions to the draft determination. AEMO and Tasnetworks preferred a standard of 1 %/% and Transgrid preferred a standard greater than (but not equal to) 0%/%.[72] One of the key reasons for this is because, in some NSPs' experience, proponents often enter connections negotiations at the MAS level and the form of the draft rule would have dulled any incentive to appropriately tune inverters to respond appropriately to alleviate undervoltage faults (by injecting reactive current) and overvoltage faults (by absorbing reactive current). This concern was also raised in the CRI's working group on reactive current access standards.[73]

The Commission acknowledges the difficulty that this can place on NSPs. However, we note the negotiation framework that is set out in the rules, which puts the onus on connecting proponents to demonstrate why they cannot meet the performance requirements under the AAS.[74] In practice, this should result in access standard negotiations commencing at or near the AAS capability level. In the event that proponents do not sufficiently demonstrate why they cannot meet the requirements of the AAS, the NSP may request justification or reject the application to connect. Indeed, we acknowledge this point being made by Clean Energy Council members that for the vast majority of connection applications, connection proponents recognise that providing too little reactive current capability will inevitably lead to delays in securing connection approval, that delay the project being registered and ultimately earning revenue.[75]

The new level of the standard is underpinned by independent technical analysis

To underpin the decision on the MAS level in the more preferable final rule, the Commission was informed by a suite of technical studies conducted by Aurecon. These have been analysed with accompanying recommendations detailed in the report, which has been

69 Ergon / Energex, submission to the consultation paper, p. 4
70 Ergon / Energex, submission to the consultation paper, p. 2
71 Submissions to draft determination: Clean Energy Council, p. 1, AEMO, p. 3, Tasnetworks, p. 2, Transgrid, p. 3.
72 Submissions to the draft determination: AEMO, p. 2; TasNetworks, p. 2; Transgrid, p. 3
73 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, p. 9
74 NER cl. 5.3.4A(b1)-(b2).
75 AEMC-CEC members workshop on 30 March 2023

published alongside this determination. This investigation ran a series of simulations on a model of a typical large (several hundred MW) wind farm, with type III turbines.[76]To investigate compliance against possible MAS of different levels, several hundred different faults were simulated, and the wind farm's response was measured. The faults can be divided into two categories:

- *balanced* — this type of fault affects all three phases of the power system equally
- *unbalanced* — this type of fault affects each phase differently. Typically, one or two phases will be faulted, while the remaining phase(s) remain healthy. These are the most common type of fault in the power system.

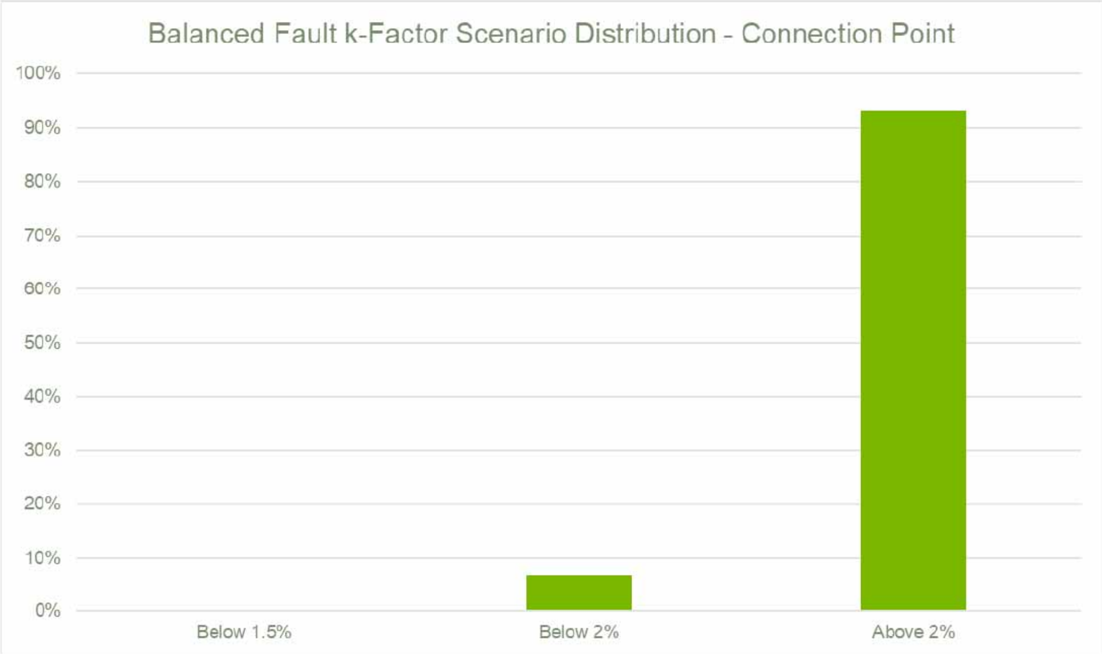
As can be seen from Figure 3.1 below, the existing standard of 2 %/% can be met in almost all balanced fault cases. This contrasts with the results for unbalanced faults, depicted in Figure 3.2, where only 20% of faults simulated saw a reactive contribution of 2% or greater from the wind farm. It can be seen from Figure 3.2, that moving to a MAS level of > 0 %/% would minimise the number of cases that result in non-compliance.

Of the resulting 5% of cases that exhibit non-compliance, most of these are cases where the plant is injecting its maximum amount of reactive current before the fault occurs. This scenario is somewhat already catered for under clause S5.2.5.5(u)(1) of the NER, which specifies that the reactive current contribution of a system may be limited to its maximum continuous current. However, in some scenarios, the occurrence of the fault will cause the system's reactive current level to drop from its maximum.

The draft rule sought to cater for these scenarios (and any other edge case scenarios) where a system's response may not exceed 0 %/%, but could be considered acceptable by allowing the NSP and AEMO to agree to a level of capability below 0 %/% on a case by case basis. The Commission has removed this provision from the more preferable final rule and considers that a broader framework for the use of engineering judgement in relation to accepting capability below minimum access standards could be considered in future access standard reform. The Commission also considers that the concerns raised by stakeholders with the negotiation framework are broader than this rule change, and could be considered in future. Further discussion on issues with the negotiation framework is provided earlier in this subsection.

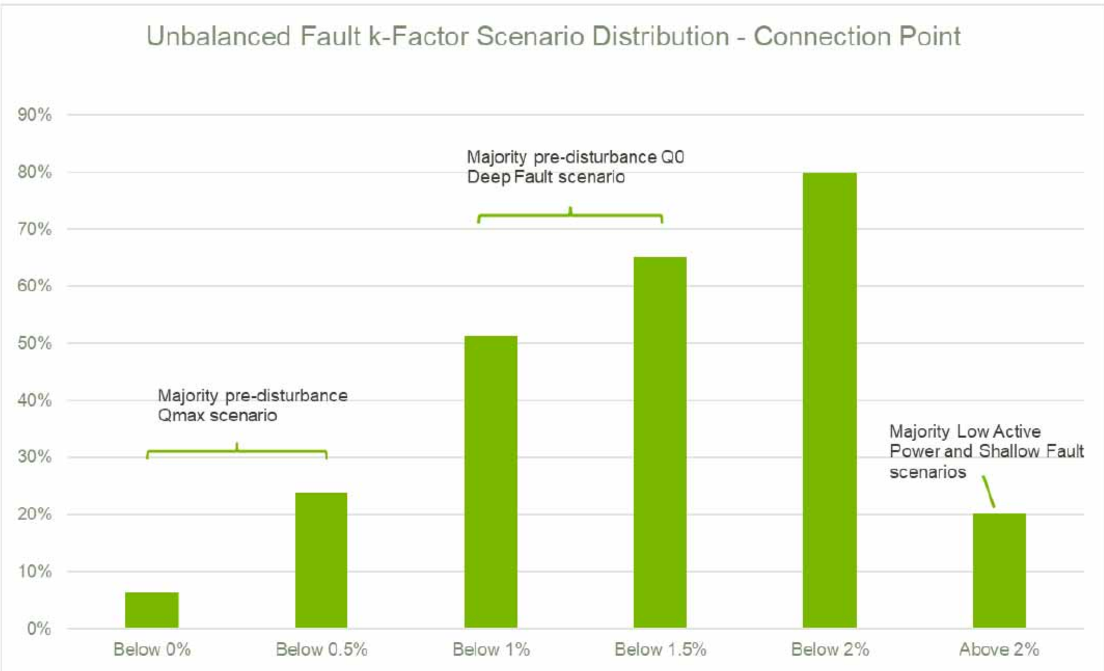
76 More details on the modelling approach and assumptions can be found in the report — here: https://www.aemc.gov.au/sites/default/files/2022-12/Aurecon%27s%20Advice%20on%20Reactive%20Current%20Access%20Standards%20Report_Rev1.pdf

Figure 3.1: MAS compliance at various capability levels for balanced fault scenarios



Source: Aurecon, Advice on reactive current access standards, p. 23

Figure 3.2: MAS compliance at various capability levels for unbalanced fault scenarios



Source: Aurecon, Advice on reactive current access standards, p. 23

Lowering the standard may result in less provision of reactive current by generators than under current arrangements, but this is likely to lead to more efficient overall provision

In submissions to the consultation paper, draft determination, and through informal feedback, some stakeholders raised the issue that reducing the level of the MAS may result in less provision of reactive current capability by generators.[77] These stakeholders noted that these costs would instead be borne by NSPs and could ultimately result in higher network charges for consumers.[78]

The Commission agrees that there would be some instances where NSPs would be required to invest in more reactive capability than under the status quo. However, we consider that the capability would likely be provided at a lower cost to consumers, for several reasons:

- NSPs would be able to harness both economies of scale and scope to cover more of the network with less capability. Their increased familiarity with their networks may also allow them to site and design investments more optimally than an equivalent investment by a generator.
- Any investment or service procurement to meet the need would be subject to the RIT, and as such would be assessed against the needs of the power system and other possible solutions. This would ensure that the installed capability corresponds with the requirements of the network, and would provide the highest benefits for consumers (noting that reliability corrective action investment needs can be met by the least cost option). This is explored in more detail in section 2.2.2.
- Synchronous condensers that NSPs install under their obligations as system strength service providers also provide reactive current support to the network. This should increase the amount of reactive capability available in the network and decrease the likelihood of shortfalls emerging.
- Where retuning of reactive plant is required due to changes in network topography and conditions that emerge over time, it is likely to be a more straightforward process if most of the assets are under the NSP's direct control.

The reactive current capability standard cannot be set at a level that will address practical difficulties with the GPS negotiation process

Throughout the consultation process for this rule change, stakeholders consistently raised concerns on the practical realities of the generator performance standard negotiation process. There was a commonly held view that the negotiation experience was inconsistent across regions, assessing parties (i.e. NSPs and AEMO) and even across individual engineers within the same organisation.

Anecdotally, there are varying perspectives across stakeholders and networks. Some proponents have noted that some NSPs are more comfortable in applying engineering judgement, while others are less so and take a much more strict interpretation of the rules, reducing the amount of flexibility available. Similarly, on the other side of negotiations, in

77 Submissions to the draft determination: TasNetworks, p. 2; Transgrid, p. 3

78 Public Interest Advocacy Centre, submission to the consultation paper, p. 1; TasNetworks, CS Energy and AEMC meeting, 6 October 2022

some instances NSPs and AEMO have observed proponents not approaching negotiations consistent with the rules negotiation framework, and proposing negotiated access standards far below the AAS with no material explanation, and evidence of minimal tuning of their plant.

These differing perspectives often led to opposing stakeholder views on various aspects of the rule, for example, the minimum level of the reactive current response. Some stakeholders felt that the minimum level of the response should be 0%/% (or below) to capture edge cases (such as during shallow unbalanced faults) where a strict interpretation of the rule could deem an otherwise acceptable response non-compliant.[79] However, other stakeholders preferred an explicit non-zero minimum level (such as 1%/%) to ensure that proponents were incentivised to make an effort tuning their plant.

In its draft determination submission, AEMO recommended that the Commission lower the reactive current capability standard to 1%/% but allow flexibility for NSPs to agree a standard below this level if that is appropriate on a case-by-case basis.[80] The submission recommended that a level below may be acceptable if:

- it occurs for a limited operating conditions so the likelihood of adverse power system impacts is low, or
- there is a benefit to the power system from reactive current injection or absorption below 1%, or
- there are sufficient other sources of reactive current in the area that NSPs can determine that additional reactive capability would not be needed at the connection point.

The Commission was of the view that it was inappropriate to set minimum access standards that are overly prescriptive or were aimed at rectifying practical issues with the negotiation framework. Rather, the minimum access standards have been set to firstly prevent detrimental system outcomes, and then provide sufficient flexibility so that negotiations can be guided by engineering considerations specific to each connection application.

Any negotiated access proposal should aim to provide the maximum reactive current capability during voltage disturbances subject to detailed engineering studies pertaining to system security and quality of supply. Examples of engineering aspects for consideration include, but are not limited to the following:

- **IBR-rich weak grid scenarios:** where there are multiple heterogenous reactive current responses in a weak area, it may be more appropriate to provide a slower, more measured response to mitigate voltage instability risks, particularly during shallow remote faults.
- **Reactive power (Q) vs active power (P) priority:** the rules imply Q priority by default, but this may not always be the most appropriate mode of operation, for example:

79 AEMC-CEC workshop with members 30 March 2023

80 AEMO submission to draft determination, p. 4

    - in low X/R ratio parts of the network where there is greater coupling between active power and voltage, e.g. distribution networks,
    - where active power withdrawal could cause a frequency contingency, or
    - in radial parts of the network where the connection point has nearby loads and Q priority may cause reversals in active power flows such that voltage stability is threatened, e.g. operation near the nose point of the PV curve.
- **Limiting overvoltages:** on unfaulted phases and post-fault during handover from fault ride-through mode. The performance of an individual plant should be calibrated so as not to exacerbate pre-existing issues, particularly in IBR-rich areas, where surrounding legacy plants may be the contributors of overvoltages during and post-fault.

These considerations are often nuanced and unique to specific situations, and the rules are not intended to be interpreted in such a prescriptive manner so as to replace engineering judgement and reasoning. There is still an obligation for proponents to aim for the Automatic Access Standards, but the Commission sees value in providing clear expectations and guidance on how proposals will be assessed. This would address stakeholder feedback that NSP/AEMO expectations and requirements are unclear and this lack of clarity can lead to unnecessary back-and-forth iterations.

As the parties best placed to understand and determine system needs, the NSPs/AEMO could consider providing proponents with guidance on various aspects of S5.2.5.5, with specific regional requirements and characteristics highlighted, for example guidance on, but not limited to the following:

- the level of performance required or expected at a specific connection point
- the method for calculating reactive current to assess different types of faults
- the expected speed of active power recovery following fault clearance
- how the definition of continuous uninterrupted operation will be practically interpreted, and
- how the undefined terms “adequately controlled” and “must not contribute excessively” will be practically interpreted.

3.1.3 Principles-based and total-current-based standards were considered but both have significant disadvantages

When considering whether a revised level of the reactive current MAS would result in better outcomes for consumers, the Commission also considered whether alternative forms of the MAS would also contribute to better outcomes. More specifically, we considered two alternative formulations of the MAS:

- principles-based, and
- total-current-based.

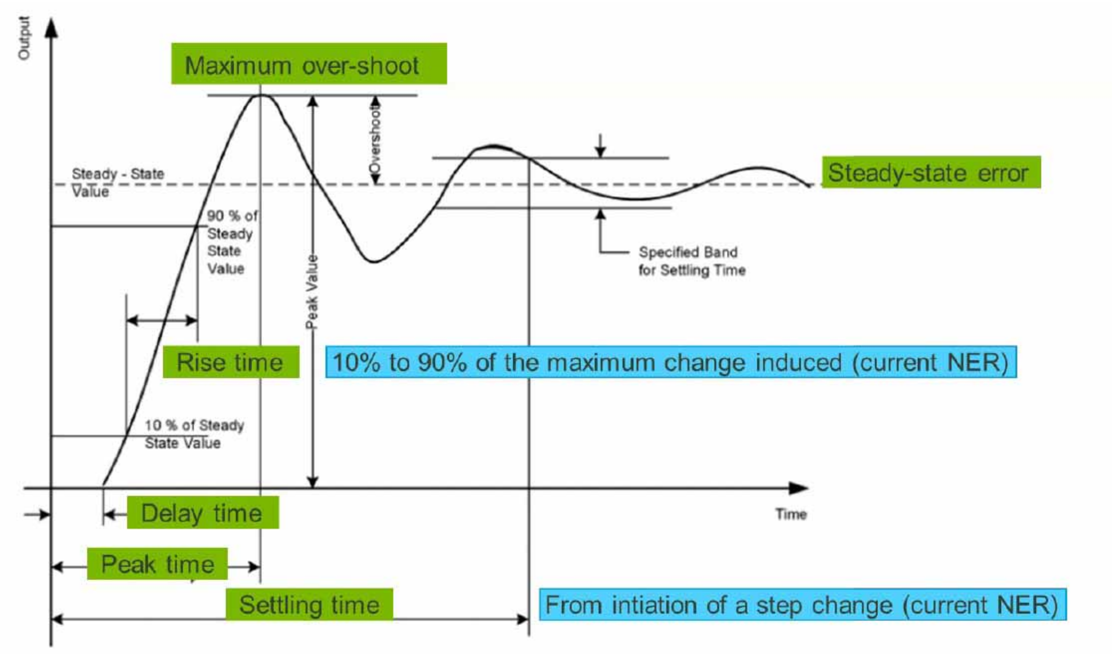
The Commission’s analysis and reasoning for why these formulations were assessed unfavourably compared to the existing, reactive-current-based formulation can be found in appendix D.

A principles-based standard was considered too open for subjective interpretation, and would remove the useful benchmark of a numerical standard for OEMs. A total-current-based standard, by comparison, was considered to be technically attractive but would introduce a variety of practical difficulties that arise from removal of the direct link between the standard base metric and voltage control.

3.2 Relaxing existing response characteristic requirements to incentivise a fast and stable reactive current response

The MAS applying at the time that the rule change request was considered required the reactive current response to rise from 10% to 90% of its maximum within 40 milliseconds (ms) of a fault.[81] The access standard also required that the response needs to settle within 70 ms.[82] The automatic access standard has the same rise and settling time requirements.[83] The rise and settling time requirements are illustrated for a stylised reactive current response in Figure 3.3.

Figure 3.3: Stylised illustration of the relationship between the cost of providing reactive current fault response capability



Source: Aurecon, Advice on reactive current access standards, p. 10.

81 NER cl. S5.2.5.5(o)(2).
82 NER cl. S5.2.5.5(o)(2).
83 NER cl. S5.2.5.5(g)(2).

AEMO states that the rules should define response characteristics such that a reactive current response to a fault incentivises fast and stable responses.[84] The more preferable final rule makes the following changes to the response characteristics to reflect this principle:

1. Deleting the settling time requirement from the rules to reflect stakeholder consensus that this is not a useful measure of the quality of a reactive current response.
2. Increasing the rise time standard from 40 ms to 80 ms to ensure that this requirement does not inadvertently contribute to voltage instability at the connection point
3. Establishing a new commencement time requirement to incentivise generators to tune control systems to start the reactive current response as soon as practicable
4. Providing flexibility to agree a longer commencement or rise time on a case-by-case basis with NSPs and AEMO if that is appropriate, and
5. Deleting the distinction in the rules that establishes different response characteristics based on reactive current responses that are either shorter or longer than 2 seconds.

3.2.1 Settling time requirement is arbitrary and has been removed

NSPs and generation project developers considered that the settling time requirement is hard to measure and interpret for real faults.[85] [86] This is because the settling time requirement is only a valid measure of the adequacy of the reactive current response for a 'clean', step response voltage disturbance. However, it is not a valid measure of an appropriate response for more complex, unbalanced faults, where there is only a disturbance on one or two of the three electrical phases. For these types of faults, settling time does not have a practical meaning over the typical duration of a fault and a response whose amplitude decays over time may constitute a poor reactive current response.[87]

The Commission agrees with stakeholders that the settling time requirement does not support an adequate reactive current response for most faults. So, designing control systems to meet this minimum access standard requirement is not supporting voltage recovery and stabilisation after faults, or system security, for the most common type of fault seen on the power system. The more preferable final rule deletes this requirement from the rules.

3.2.2 An 80 ms rise time standard should reduce the risk of connection point voltage instability after a disturbance

The more preferable final rule maintains the draft rule's position on rise time, and specifies that the reactive current fault response must have a rise time of 80 ms or less. It also retains the draft rule's flexibility to agree to longer rise times where the NSP and AEMO see fit. Substantial consultation was undertaken on this element in the draft stage of the rule change, but in responding to the draft determination, stakeholders did not comment on rise time.

84 AEMO submission to consultation paper, p. 4.
85 Submissions to the consultation paper: Windlab, p. 1; AEMO, p.4
86 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, p. 16
87 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, p. 16.

The Commission heard a number of different criticisms of the rise time standard from OEMs, project developers, NSPs, AEMO and the CRI. AEMO and the CRI noted that the rise time standard is hard to measure, and is only a relevant measure of response-quality for simple, step-response voltage disturbances.[88] OEMs and generation project developers recommended a more lenient standard that may incentivise a response that stabilises voltages at the connection point as soon as practicable while mitigating instability under some fault and pre-disturbance generator operating conditions.[89]

Voltage instability can arise from rapid levels of reactive current injection that cause large changes in connection point voltage levels, especially in weak grids. This effect is analogous to a large force being applied to a low stiffness spring, which can lead to the spring being hard to control and return to a stable state. In the electrical context, GE noted that this instability can be hard to control once it starts and can lead to increasingly distorted voltage waveforms that ultimately lead to connected generators (and potentially other nearby loads) losing synchronisation with the network and disconnecting.[90]

Both Energy Queensland and Powerlink agreed that the existing rise time standard needs to be revised as a number of connecting parties are not able to meet the current standard. Energy Queensland's view was that this could be addressed without lowering the reactive current capability standard.[91] [92]

However, AEMO and the CRI's technical paper did not support retaining the rise time standard. AEMO noted that the rise time standard has been specified for a very specific type of balanced, three-phase fault with a clean step characteristic, which is rare in practice.[93] Powerlink disagreed with AEMO's critique that the rise time is hard to measure and assess in practice. Their representative noted that they account for whether the reactive current response has risen to a level that is appropriate to the fault being considered, when assessing generation project proponent's connection studies.[94] OEMs agreed with Powerlink's assessment of how compliance with rise time standards is typically assessed by other NSPs.[95]

The Commission recognises that a short rise time is needed to ensure that the reactive current response rises quickly to arrest the voltage disturbance. However, a response that rises too quickly, in weak systems can create instability. The rule change proposal also noted that this is not helped by installation of additional auxiliary equipment, such as STATCOMs. In short, the current rise time standard does not support the efficient achievement of system security objectives.

88 AEMO submission to consultation paper, p. 4.
89 GE International Inc. meeting with AEMC staff on 20 October 2022; Windlab submission to consultation paper, p.5.
90 GE, Discussion with the AEMC, 20 October 2022.
91 Ergon and Energex joint submission to consultation paper, p. 10.
92 Powerlink discussion with AEMC staff 22 August 2022
93 AEMO submission to consultation paper, pp. 4-5.
94 AEMO noted that measuring the rise time standard at the connection point can be challenging, as fault characteristics often mean that the reactive current response does not need to rise from 10 to 90% of its peak value.
95 Powerlink representative comment in TWG meeting 3.

The Commission explored two options to assess how the rise time standard could better support efficient system security outcomes.

1. a principles-based standard that would require a reactive current response to be fast, stable and return voltages to stable levels as soon as practicable;
2. increase the rise time standard to mitigate the risk to instability and introduce a new standard to incentivise fast response commencement.

Lengthening the rise time standard would allow OEMs to tune their equipment to meet a particular reactive current response benchmark. However, a longer rise time standard could also mean a slower response. To address this risk, the more preferable final rule splits the requirement for a response to be fast from the rise time standard (option 2 as described above). This has led to the more preferable final rule implementing a version of AEMO's recommendation to introduce a commencement time standard assessed from a response initiating condition that AEMO, NSPs and generators agree on (see section 3.2.3).[96]

The Commission did not support the alternative formulation of the rule that would see the establishment of a strictly qualitative standard (option 1 described above) because that would ultimately lengthen NSP-generator negotiations on how control systems are tuned. It would also open project developers to the risk of different NSP interpretations of the standard by NSPs across the NEM jurisdictions.

Aurecon's modelling informed the establishment of the 80 ms standard

The Commission's view on an 80 ms rise time standard was informed by Aurecon's PSCAD modelling of a hypothetical 500 MW wind farm. This showed that a rise time standard at 80 ms measured at the connection point is likely to be met under 95% of fault, and pre-disturbance active and reactive power output conditions (see Figure 3.4). The modelling also showed that compliance with a rise time standard of more than 60 ms is not sensitive to locational short-circuit ratios.

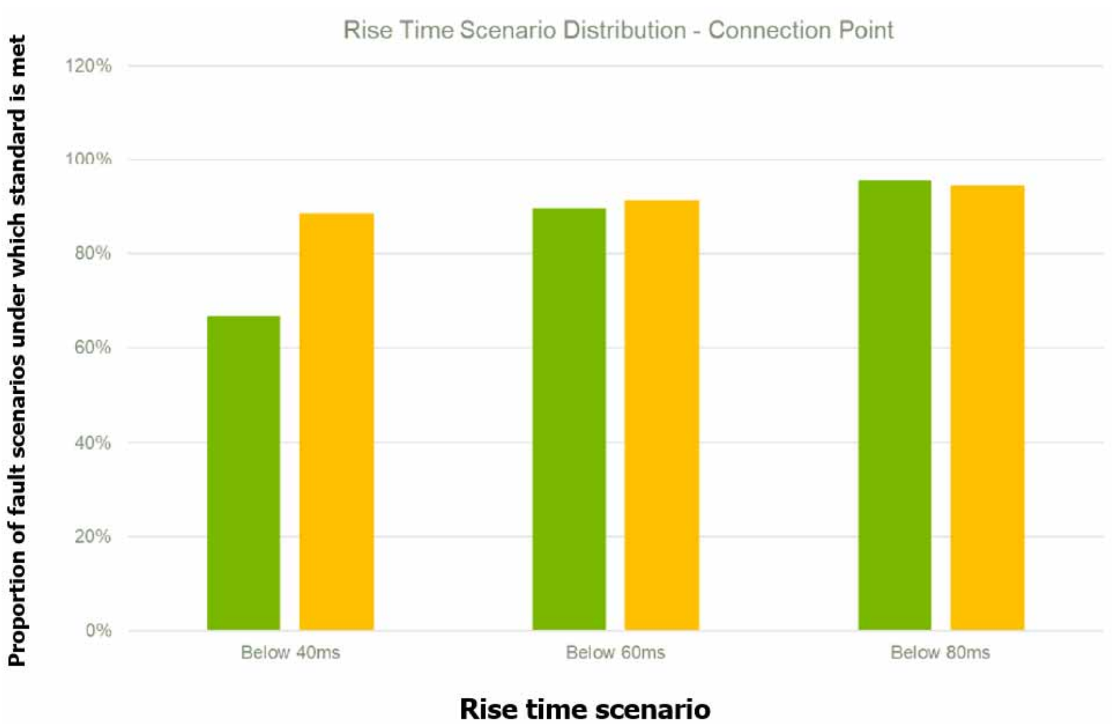
The 5% of modelled fault/pre-disturbance operating scenarios under which a revised 80 ms rise time standard is not met are characterised by distortions in the reactive current injection waveform during the initial stages of the fault, and operating conditions where reactive current was being absorbed by the wind farm before it needed to be injected.[97]

To account for the specific cases where the rise time standard cannot be met the more preferable final rule would also allow NSPs, AEMO and generators to agree an alternate standard that is appropriate for a given connecting site on a case-by-case basis. This flexibility would support the achievement of system security objectives at least cost, by allowing NSPs and AEMO to apply their engineering judgement to assess if the fault/pre-disturbance scenarios where the rise time standard is not met are likely to present material risks to secure power system operation. Stakeholders did not raise any concerns with this change in their submissions to the draft determination.[98]

96 AEMO submission to consultation paper, p. 5.
97 Aurecon, Advice on reactive current access standards, p. 19.
98 Submissions to draft determination: CEC, pp.1-2, AEMO, pp. 4-6

Aurecon's simulations found that solar farms and battery energy storage systems were able to achieve faster rise times than wind farms.[99] However, the Commission notes that given the rule change is to revise the MAS, the proposed revision should be based on the lowest acceptable performance that is valid for all IBR technologies rather than the best response that could be expected from an IBR connection.[100]

Figure 3.4: Proportion of wind farm fault response scenarios that meet a specified rise time standard for grids with short-circuit ratios of 2 and 5.



Source: Aurecon, Advice on reactive current access standards, p. 19.

3.2.3 The more preferable final rule implements a commencement time of 40 ms to incentivise a fast response to voltage disturbances

As outlined in section 3.2.2, the more preferable final rule maintains the draft rule's position and establishes a new commencement time requirement to incentivise a fast reactive current response that ensures an over or under voltage fault does not get worse. AEMO noted that its investigations of the performance of plant for connection studies indicate that most asynchronous generators should be able to meet a requirement of 30 ms or less.

The more preferable final rule implements a commencement time of 40 ms, with the provision for longer times to be agreed where AEMO and the NSP see fit. This should provide added flexibility to ensure that the minimum access standard covers the broadest range of

99 Aurecon, Advice on reactive current access standards, p. 27.

100 Aurecon, Advice on reactive current access standards, p. 19.

fault and generator pre-disturbance response conditions. This is supported by Aurecon's modelling which suggests that a MAS of 30 ms may result in non-compliance in up to 20% of operational fault scenarios during unbalanced faults for a hypothetical 500 MW wind farm.[101]

The more preferable final rule also allows the commencement time to be assessed from a 'response initiation condition' that is agreed by NSPs, generation project proponents and AEMO, and that this be recorded in the generator's performance standard. AEMO recommended that the response initiating condition could be voltage traversing a voltage threshold, voltage going beyond a given excursion, or another point that connecting parties agree on.[102]

In responding to the draft determination, most stakeholders did not comment on this specific provision. Powerlink noted its support, while AEMO suggested that the rules should set out the conditions for which commencement times higher than 40 ms could be agreed.[103]The Commission has not adopted this proposal, as it considers that NSPs and AEMO possess sufficient technical expertise and negotiating power to use their engineering judgement on this matter on a case-by-case basis.

In informal conversations and one submission to the draft, several stakeholders observed that the proposed new Minimum Access Standards introduce inconsistencies with the Automatic Access Standards.[104]For example, a commencement time requirement was introduced in the MAS, but not in the AAS. The Commission acknowledges this inconsistency and considers that the AAS could be aligned through potential rule changes arising from AEMO's technical standards review. However, the Commission notes that the AAS and MAS don't necessarily need to align; the MAS is simply a standard that must be met by all connecting generators, while the AAS guarantees the connecting generator a negotiation-free connection with respect to that particular requirement.

3.2.4 The more preferable final rule includes added flexibility to allow NSPs and AEMO to apply reasonable engineering judgement

With respect to both the rise time and commencement time standards, the more preferable final rule maintains the position of the draft rule and provides additional flexibility to account for a particular combination of fault, network or generator connection conditions where it is not possible to meet the revised rise or commencement time standard. In these circumstances, NSPs and AEMO can take one of two courses of action:

1. Require the party seeking connection to install auxiliary plant to ensure that they meet the rise time benchmark
2. NSP to propose an alternative rise time benchmark that is longer than 80 ms, specified in the rules.

101 Aurecon, Advice on reactive current access standards, p. 29. Aurecon recorded commencement time as the point at which the reactive current injection/absorption waveform crosses zero, 20 ms after the fault starts.

102 AEMO submission to consultation paper, p. 4.

103 Submissions to the draft determination: AEMO, p. 6; Powerlink, p. 2

104 APD Engineering, submission to the draft determination, p. 3

The flexibility introduced by the more preferable final rule is designed to enable NSPs and AEMO to apply engineering judgement when evaluating the risk of non-compliance with the numeric rise or commencement time standard. For example, connection studies may show that the connecting plant does not meet the numeric rise or commencement time standard under a specific pre-disturbance condition.

However, the Commission considers that it may be valid for NSPs and AEMO to accept a longer rise or commencement time standard for a particular generator's performance standard, if for instance, they assess that the particular scenario or scenario(s) where non-compliance is observed is of:

- sufficiently low probability, or
- the risk of non-compliance with the numeric standard in the rules is not likely to present a material system security risk (e.g. because of the size of the connecting facility, or the characteristics of the connecting location), or
- if the facility is likely to provide other system security benefits (e.g. for voltage waveform quality, or to support frequency management objectives).

AEMO recommended that these requirements be included in the rules but the Commission has concluded that providing prescriptive guidance on one element of the rules would be outside the scope of this process. We also acknowledge that AEMO is considering these matters as part of its first, five-yearly review of technical access standards for inverter based plant.[105] However, for the reasons outlined in section 3.1.2, the Commission has determined not to address broader issues with the interpretation of particular clauses, through further amendments in the rules and recommend that the solution to these issues are better considered through

The more preferable final rule provides added flexibility for NSPs to disallow poorly controlled responses by replacing the requirement for responses to be adequately damped with a requirement that the response be adequately controlled. A number of stakeholders responded to the draft determination.

The Commission has made this assessment because it is difficult to formulate a numeric standard for rise and commencement time that is likely to be valid for all connecting scenarios and/or circumstances. Pragmatic flexibility to allow the use of reasonable, expert engineering judgement was a key theme in stakeholder feedback over the course of the Commission's consultation on this rule change.

3.2.5 Removing the distinction for response characteristics based on whether the response is longer or shorter than 2 seconds

The more preferable final rule maintains the draft rule's position and corrects an inconsistency between the practical operation of generator control systems and the current bifurcation in the rules on how a reactive current response should behave depending on whether the response is shorter or longer than 2 seconds.

105 AEMO submission to draft determination, p. 6

This change recognises that a generator's control system will not know how long the reactive current response will need to last before it commences. In order to support transparency and simplicity of the rules, the more preferable final rule deletes the distinction between responses shorter or longer than 2 seconds from the rules.

No feedback on this matter was received in submissions to the draft determination.

3.3 Establishing simpler and more technology-neutral control system response requirements for reactive current responses

There are three key issues with the way the rules that apply when we considered this rule change specify when and how a control system should respond to a voltage disturbance with reactive current, which may in the future cause issues for generators and/or NSPs.

The more preferable final rule addresses these issues by:

1. **Requiring generators' reactive current response to start at any point up to an under voltage threshold of 80% of the connection point normal voltage or 120% of the connection point normal voltage for overvoltage faults or another voltage range as agreed with NSPs and AEMO.**

   The former rules required generators' reactive current responses to start in the range 80 to 90% of connection point normal voltage for under-voltage faults, or 110 to 120% of connection point normal voltage for over-voltage faults or another voltage range as agreed with AEMO and NSPs.[106] [107] The rules disadvantage generators that do not employ fault ride-through capability or employ GFI technology, which starts their reactive current response as soon as voltage exceeds a given excursion limit. To support system security at least cost, the Commission has made the proposed change to allow newer technologies to connect to the transmission network more easily.

2. **Requiring that the time frame within which a generator's active power needs to recover to 95% of its p level also take into account whether voltage has recovered to between 90% and 110% of connection point normal voltages and for the time taken for active power recovery to be recorded when voltages remain in that range.**

   The rules prior to the commencement of this final rule require generators to ensure active power to recover to 95% of its pre-fault level after the fault clears, within a period of time agreed by the connection applicant, NSP and AEMO.[108] The CRI technical report noted that this requirement is at odds with the physical limits of generator operation for two reasons: first, active power cannot physically recover when voltages are still depressed, second, active power cannot physically recover when there is a need to prioritise reactive power injection to push voltages up to the normal operating range designed to support continuous uninterrupted operation.[109] The Commission considers

106 NER cl. S5.2.5.5(o)(1).

107 This change from the draft determination to the final addresses an inadvertent issue with the form of the draft rule. See submissions to draft determination: Gridwise energy solutions, p. 2, Transgrid, p. 4.

108 NER cl. S5.2.5.5(n)(2).

that this form of the more preferable final rule will help support a more transparent and simpler rules framework by removing a source of internal inconsistency in this access standard framework. The more preferable final rule also clarifies an issue with the draft rule which introduced ambiguity regarding how the time taken for active power recovery should be recorded. The Commission has done this by noting that the time taken for active power recovery is to be recorded while voltages remain in the range 90 - 110% of normal voltage, instead of the earlier drafting which said voltages were required to be stable in that range.[110]

3. **Establishing a requirement that allows NSPs to require connection applicants to ensure that they do not contribute to excess voltage increases on unfaulted phases of a three-phase electrical network during unbalanced faults.**

   This is often negotiated on an informal basis between generators and NSPs but there was a desire for this requirement to be codified.[111] The more preferable final rule has made this change to help ensure that NSPs have appropriate recourse to ensure that generators do not tune their equipment in a way that worsens behaviour of the most common type of fault seen on the power system. Codifying an existing practice was not seen to lead to generators having to bear any additional costs for maintaining system security but may ensure that poor control system design practices are reduced or eliminated.

3.3.1 Commencement of generators' reactive current response

The wind OEM's rule change request proposed some minor amendments to the response commencement thresholds. Stakeholders elaborated on the issue in their responses to the consultation paper, with both Tesla and AEMO noting issues with the commencement thresholds. The final rule addresses mostly maintains the draft position of adopting AEMO's proposal and allowing for commencement thresholds to be agreed at any point in 80% - 100% normal voltage for undervoltage faults, and 100% - 120% normal voltage for overvoltage faults. It also includes flexibility for thresholds outside these ranges to be agreed where the NSP and AEMO see fit.

Tesla's submission noted that generators that employ GFI behave like synchronous generators, in that they constantly control voltages through continuous reactive power control, independent of any threshold. This includes in the normal voltage operating range. This can result in the part of the plant's response that occurred inside the range not being counted, resulting in difficulties meeting the response magnitude requirements of the standard. Tesla noted that the current rules lead to plant that can employ GFI capabilities effectively detuning those characteristics to demonstrate compliance with the rules.[112]

AEMO's consultation paper submission also noted that commencement based on a trigger voltage reflects the capability of grid following inverters, and is therefore not technology

109 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standards, p. 10.
110 AEMO submission to draft determination, p. 5.
111 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standards, p. 18.
112 Tesla submission to consultation paper, p. 8.

neutral. AEMO considers this is problematic because current requirements may also be contributing to a delay in how quickly a response commences, especially if a generator does not employ fault ride through capability or can employ grid-forming inverters but this has been detuned to comply with existing rules.[113]

In their feedback to the draft determination, GridWise and Transgrid both noted that the rules should maintain the flexibility to agree commencement thresholds outside the prescribed ranges where the NSP and AEMO see fit, as is possible under the status quo.[114] The Commission considers this suggestion would increase the flexibility available to proponents, NSP and AEMO to best balance costs and the security needs of the power system, and has thus included the provision in the more preferable final rule.

Other solutions considered

The CRI's technical paper proposed an alternate, viable solution. This solution would maintain the rules as they are currently written but create an option that would allow NSPs, AEMO, and connection applicants to respond to an under- or over-voltage threshold outside the range in the rules if that is appropriate on a case-by-case basis.[115]

However, the Commission concurs with AEMO's assessment that its proposed formulation would provide more flexibility for the different types of fault/pre-disturbance generator operating conditions and inverter technologies that will be connected. It will do so while still establishing upper and lower boundaries for when a reactive current response should commence.[116]

The Commission also believes that AEMO's proposal is simpler than that proposed by the CRI in its technical paper, with this view informed by discussions with stakeholders at the third TWG meeting.

The Commission did not support one other potential solution to this issue raised by Tesla. Tesla proposed that the rules should be revised to allow asynchronous generators that employ grid forming inverters to be considered under the connection standards that apply to synchronous generators.[117] However, there is no agreed definition on the characteristics of technologies that employ GFI.

AEMO's access standards review is considering whether a definition for GFI should be provided.[118] The Commission agrees with the CRI technical paper that this matter is outside the scope of this rule change and notes that this is also being considered as part of AEMO's Access Standards Review.[119]

113 AEMO submission to consultation paper, p. 6

114 Submissions to the draft determination: GridWise, p. 2; Transgrid, p. 4

115 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, p. 17.

116 AEMO submission to consultation paper, p. 6.

117 Tesla submission to consultation paper, p. 8.

118 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, p. 12.

119 AEMO, AEMO review of technical requirements for connection - Approach Paper - Pursuant to clause 5.2.6A of the NER, Oct 2022, p. 10.

3.3.2 Providing clarity on active power recovery after fault clearance

The Commission notes that there is an inconsistency in the rule requirement for reactive current response to be maintained until connection point voltage levels recover to between 90% and 110% of the normal voltage[120] and the next clause which requires active power to recover to 95% of its pre-fault level after fault clearance.[121] Active power also cannot physically recover until voltage levels have recovered to between 90 and 110% of connection point normal voltage.[122] Therefore, any negotiation of the time that should be allowed for active power recovery has to take into account voltage recovery.

The CRI technical paper recommended that this could be addressed by requiring that voltage stabilisation to between 90% and 110% of the connection point normal voltage be included as a factor that is considered alongside fault clearance in connecting parties determining how quickly active power should recover to its prefault level.[123] However, AEMO's draft determination submission noted that the use of the word 'stable' in the rules would lead to unnecessary interpretation issues that affect interpretation of the starting point for calculating how long active power should take. That is, it would lead to questions on what characteristics of voltage measured at the connection point constitutes stable recovery of voltages. To clarify this ambiguity and support transparency and simplicity of the access framework, the Commission has made a change to note that active power recovery should occur when voltages remain in the range 90 - 110% connection point normal voltage.

3.3.3 Codifying existing arrangements to avoid excessive voltage rise on unfaulted phases

Unbalanced faults are the most common type of fault seen on the power system. An appropriate reactive current response to these types of faults requires injection or absorption of reactive current in only the phase on which there is a disturbance. However, a reactive current response that is not adequately controlled may see injection of reactive current to 'healthy' phases, which leads to the disturbance spreading to multiple phases of the network.

The Commission considers that generators' control systems do not inadvertently cause disturbances on phases unaffected by a fault. The more preferable final rule codifies this and provides a mechanism for NSPs to require generators to control their reactive current response to ensure that they do not contribute to 'excessive' voltage increases on unfaulted phases of the network during unbalanced faults. This was supported by discussions at the third TWG meeting.

3.4 Providing definitional clarity to support easier negotiation of connection agreements between generators, NSPs and AEMO

It is important that all parties in the connection process have a common understanding of the capabilities required and how they will be assessed. The OEMs' rule change request raised three terms where they consider that additional definitional clarity would make the

120 NER cl. S5.2.5.5(n)(1).

121 NER cl. S5.2.5.5(n)(2).

122 GE presentation to AEMC staff, October 2022.

123 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, p. 13.

connections process more transparent and straightforward. They noted that the lack of clarity can lead to confusion and delays in the connection process. For example, delays may ensue if the NSP and proponent are working from different definitions.[124] The terms that the OEMs consider would benefit from further (or any) definitional clarity are:

- *Maximum continuous current*,
- *Continuous uninterrupted operation (CUO)*,
- *Reactive current*.

3.4.1 Defining 'maximum continuous current' would provide all stakeholders with clarity on the base against which reactive responses are measured

As both the OEMs' and RER rule changes note, maximum continuous current was undefined in the rules. It refers to the largest amount of current that a generating system is expected to produce. Additionally, it is the 'yardstick' against which the rules specify the magnitude of the system's reactive current response.

Multiple potential definitions were discussed throughout the stakeholder consultation process, some relating to assessment points at the unit terminals, and others at the connection point. Consistent with the rest of the reactive current MAS, we consider that maximum continuous current should be defined on a system level, typically at the connection point, and as such we have preferenced definitions relating to the connection point. We considered the following definitions for *maximum continuous current*:

1. the registered capacity of a generating system divided by the connection point voltage
2. the current at the connection point corresponding to the largest amount of apparent power required by the system's performance standard under clause S5.2.5.1 of the NER
3. the nameplate rating of in service units, divided by the terminal voltage
4. the maximum continuous current a unit can deliver at its terminals, derived from its nameplate rating, its apparent power rating, and permitted range of voltage for continuous uninterrupted operation

The Commission prefers option 2 as it provides a clear, defined yardstick for proponents to optimise their response against, while still providing NSPs.

The more preferable final rule includes a generating system's *maximum continuous current* as a defined term in Chapter 10 of the rules, corresponding to the largest amount of apparent power required by the system's generator performance standard, under clause S5.2.5.1 of the NER. To provide additional flexibility, if a connecting generator seeks compliance assessment at a point other than the connection point, the more preferable final rule also adds another limb to the definition to allow *maximum continuous current* to be calculated at a point other than the connection point (e.g. the unit terminals or somewhere else within the internal reticulation system). The Commission's definition does not provide a way to calculate maximum continuous current at the unit terminals, or somewhere between each unit and the generating system's connection point. The Commission believes that the

124 GE International Inc., Goldwind Australia, Siemens Gamesa Renewable Energy, Vestas Australia, National Electricity Rule Change Proposal Reactive current response to disturbances (S5.2.5.5), pp. 10-12

maximum continuous current is assessed at the unit terminals the value should be based on the rated apparent power of each generating unit and if compliance is assessed at a different location then location specific derating limits should be agreed. The Commission considers that this definition provides stakeholders with certainty and clarity, while providing flexibility in the value for each connection.

Stakeholders have been unanimous in their feedback that it would be beneficial to define *maximum continuous current* in the rules, reiterating that this would provide greater clarity and transparency in the connections process.[125][126] [127]

3.4.2 The status quo definition of 'continuous uninterrupted operation' will be maintained

The OEMs' rule change request considers that the definition of 'continuous uninterrupted operation' (CUO) can be interpreted to require the power system's voltage response following a fault to remain the same with or without the project.[128] This does not acknowledge that the addition of a new generating system will inherently change the response in some way. The more preferable final rule is to retain the existing rule.

The reactive current access standards in the rules state that generating systems must remain in CUO for various, defined circumstances. Part (d) specifies that following a power system disturbance, generating systems should not exacerbate or prolong the disturbance or cause a subsequent disturbance for other connected plant, except as required or permitted by their performance standards. The OEMs' request notes that this has, on occasion, been interpreted strictly to mean that there should be no variation in connection point voltage response with or without the project present in simulations. However, the intent of the definition is to prevent any adverse impact on other generators, network users or in general operations of the power system but has been strictly interpreted in some cases without a view to the transient behaviour of power systems during and just after a disturbance.

In the TWG, stakeholders noted that the aforementioned interpretation ignores whether these variations represented a material degradation in the response of the power system.[129] It also does not acknowledge that the addition of a new generating system will inherently change the response in some way. The draft rule sought to address this issue by requiring that disturbances that one generator is responding to is not prolonged in a way that leads to subsequent disturbances for other generators. However, AEMO's draft determination submission sought to broaden this change further by requiring that assessment of whether a generator remains in CUO depends on whether their response to a particular disturbance adversely impacts the stability of other connected plant.[130]

On balance, the Commission considers that changing the form of the rules is not needed if AEMO and NSPs interpret this clause in the way it was intended — that is accept, that new

125 Submissions to the consultation paper: CEC, p. 3; AEMO, pp. 7-9

126 Vysus Group, Proposed changes to NER S5.2.5.5 minimum access standard, 6 June 2022, pp. 9-11.

127 Submissions to draft determination: Powerlink p. 1, AEMO p. 3, Transgrid p. 2, Gridwise energy solutions, CEC, p.1.

128 GE International Inc., Goldwind Australia, Siemens Gamesa Renewable Energy, Vestas Australia, National Electricity Rule Change Proposal Reactive current response to disturbances (S5.2.5.5), pp. 11-12

129 AEMC reactive current technical working group 3, 27 October 2022

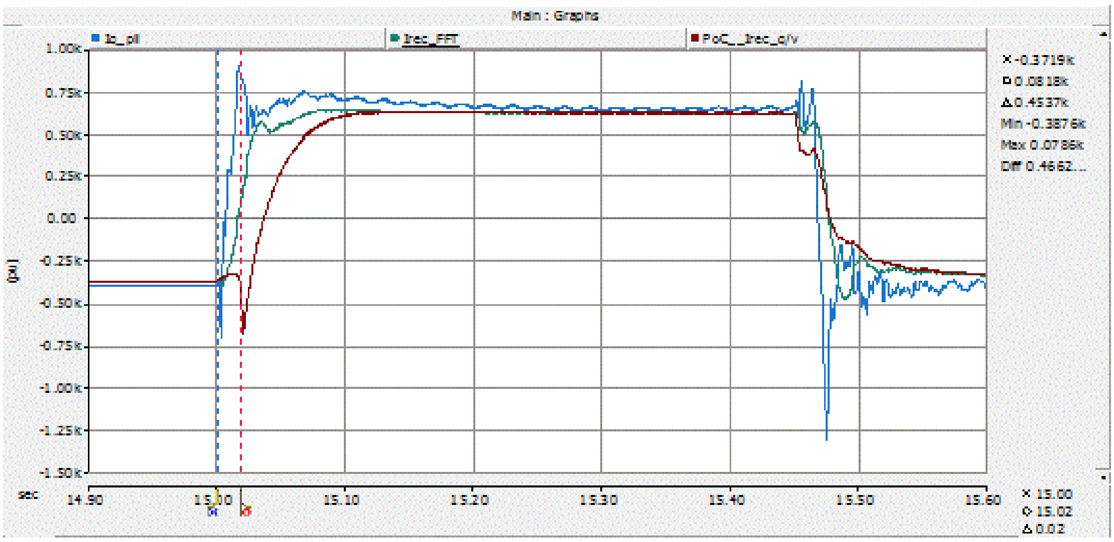
130 AEMO, submission to the draft determination, p. 5

plant to the power system will inherently change the voltage response of the system in some way. Rather, NSPs and AEMO interpretation of CUO should acknowledge that variations in the power system's fault voltage response with the addition of a new plant are acceptable as long as they do not represent a material degradation of the response. The more preferable final rule thus retains the status quo definition of CUO.[131]

3.4.3 Reactive current would remain undefined, but we expect NSPs to provide more guidance to proponents on the definitions used to assess different faults

Reactive current is a mathematically derived quantity reflecting the component of current (a physical quantity) that contributes to reactive power. There are a number of methods for calculating reactive current and while it has been observed that results are fairly consistent across different methods for balanced (symmetrical) voltage disturbances, material differences are observed during unbalanced scenarios.[132] For example, Figure 3.5 below shows the results from three different methods for calculating reactive current during a disturbance.

Figure 3.5: Reactive current derived from various calculation methods



Source: Vestas

In earlier rounds of consultation, stakeholders have noted that there isn't a universally accepted calculation method and different methods are often used to analyse different types of faults.[133]We note that the normative Annex C of international standard IEC 61400-21:2018 articulates a calculation method based on Fourier analysis, though it is acknowledged that the IEC 61400 series of standards are specifically written for wind turbines.

131 This decision has been informed by bilateral conversations between draft and final.

132 For example, refer to J. Niiranen, "*About the Active and Reactive Power Measurements in Unsymmetrical Voltage Dip Ride-through Testing*", Wind Energy, **11**:121-131, 2008

133 GE International Inc., Goldwind Australia, Siemens Gamesa Renewable Energy, Vestas Australia, National Electricity Rule Change Proposal Reactive current response to disturbances (S5.2.5.5), p. 10, 20, 21

In their submission to the consultation paper, Renewable Energy Revolution (RER) also pointed out that "reactive current" is not a defined term in the NER,[134] and that the rules are also largely silent on how reactive current is intended to be calculated.[135] In submissions to the draft determination, no stakeholders explicitly provided any feedback on this issue.

Due to the variance in the calculation method that is appropriate for different types of fault, the Commission considers that outlining the appropriate method for each type of fault would be overly complex and falls beyond the scope of the rules. Instead, we expect each NSP to produce guidance (where it hasn't already done so) for connection proponents to reference as they optimise their plant. While the more preferable final rule does not specify this as a specific rules requirement, we expect NSPs would do so, as it would benefit both parties in the connection process by reducing the amount of iteration that is required during assessments.

134 RER, submission to the consultation paper, pp. 5-9

135 With the exception of the sentence "*the reactive current contribution required may be calculated using phase to phase, phase to ground or sequence components of voltages*" in NER Clause S5.2.5.5(u)(3)

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery energy storage system
CEC	Clean Energy Council
Commission	See AEMC
CRI	Connections Reform Initiative
GFI	Grid forming inverter
IBR	Inverter-based resource
IESS Rule	National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021 No. 13
MAS	Minimum access standard
NEL	National Electricity Law
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NGL	National Gas Law
NGO	National gas objective
NSCAS	Network support anciliary service
NSP	Network service provider
OEM	Original equipment manufacturer
PIAC	Public Interest Advocacy Centre
PSCAD	Power system computer aided design
RER	Renewable Energy Revolution Pty Ltd
RIT	Regulatory investment test
SSSP	System strength service provider
STATCOM	Static synchronous compensator
TNSP	Transmission network service provider
TWG	Technical working group
X/R	Reactance to resistance

A RULE MAKING PROCESS

This appendix outlines the rule change request and the related consultation processes that the Commission undertook.

A.1 Rule change requests

The Commission consolidated two closely related rule change requests from Renewable Energy Revolution (RER) and a consortium of wind turbine OEMs on 26 May 2022. RER submitted its rule change request on 2 April 2019 and the wind turbine OEMs submitted their request on 11 March 2021.

The rule change requests included proposed rule drafting.

A.1.1 Rationale for the rule change request

Both rule change requests sought to better align the minimum level of reactive current capability that asynchronous generators needed to provide to the needs for voltage support capability after faults.

The wind turbine OEMs rule change proposal noted that the current standards are leading to investment in auxiliary reactive current capability equipment to meet the numeric benchmarks specified in Schedule 5.2.5.5 that are not tied to clear system security benefits. These numeric benchmarks specify the negotiation of:

- how much reactive current capability generators need to provide in response to a fault,
- when that response needs to commence
- how that response needs to be controlled and
- how quickly active power needs to recover after a fault.

The wind turbine OEMs noted that this leads to connection applicants seeking to connect smaller, less efficient generating systems to reduce the cost of demonstrating compliance with the minimum access standards. However, splitting larger projects into smaller ones creates more complexity during, construction, commissioning and operation.

In other circumstances, the OEMs noted that current standards will delay new projects coming into operation because of complexities that arise through the generator performance standard negotiation process. This process often leads to wind farms having to invest in auxiliary equipment that increases project costs, which are ultimately passed onto consumers in the form of higher generation costs.

Both the wind turbine OEMs' and RER's rule change requests noted that the current, minimum reactive current capability standards may be having detrimental impacts on system security in medium and low voltage points of connection. The rule change requests noted that these outcomes can come about in one of two ways:

- RER noted that investment in auxiliary dynamic reactive control devices to meet the reactive power capability standard may be leading to too much reactive current being injected to weak parts of the power system, after faults. This often leads to large changes in voltage at the connection point, which can be difficult to control.

- In some areas, frequency deviations may be more important or difficult to control than voltage fluctuations. This standard is creating an incentive for generators to prioritise of reactive power to address voltage faults, which can lead to an active power penalty and subsequently worsen frequency deviations.

A.1.2 Proposed solutions

The solution proposed by the wind turbine OEMs to address the problems they identified had four elements. They proposed that the rules:

1. Should shift the point of compliance assessment from the connection point to the generator unit terminals for parameters defining:
    - how much reactive current capability generators should be required to provide and
    - how quickly the response needs to start, and
    - how quickly the response should rise from 10 to 90% of its maximum level and then settle within an acceptable degree of fluctuation
2. Should require that the level of reactive current capability provided at the connection point be at least at its pre-disturbance level after the reactive current response has stabilised, and
3. Should define maximum continuous current based on the maximum apparent current rating of each generating unit under normal conditions.

RER proposed that the issue with the current standard be addressed by aligning the reactive current capability standard to the connection point reactance to resistance ratio (X/R).

RER proposed that the maximum reactive current capability should be less than the maximum continuous current of the generating system to allow active power to also contribute towards maintaining stable voltage levels. This solution was suggested because at low X/R ratios (of 2.5 to 8 - which are typically observed in medium to low voltage parts of the network), active power can help support voltage, alongside reactive power.

A.2 Consultation process

A standard rule change request — of which this is one — includes the following formal stages:

- a proponent submits a rule change request
- the Commission commences the rule change process by publishing a consultation paper and seeking stakeholder feedback
- stakeholders lodge submissions on the consultation paper and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a draft determination and draft rule (if relevant)
- stakeholders lodge submissions on the draft determination and engage through other channels to make their views known to the AEMC project team

- the Commission publishes a final determination and final rule (if relevant).

Oweing to additional consultation undertaken due to the complexity of the issues explored throughout the rule change process, the timeframes were varied from the standard rule change process as follows:[136]

- draft determination publication was extended to 3 November 2022
- draft determination publication was extended again to 15 December 2022
- final determination publication was extended to 20 April 2023

You can find more information on the rule change process in The Rule change process – a guide for stakeholders.[137]

For this rule change, the Commission discussed and sought stakeholder input on the relevant issues through technical working group meetings as set out below.

A.2.1 Consultation paper

On 26 May 2022, the Commission published a consultation paper seeking input on the consolidated rule change requests from Renewable Energy Revolution Pty Ltd and a consortium of wind turbine original equipment manufacturers comprising GE International Inc., Siemens Gamesa Renewable Energy, Goldwind Australia, Vestas Australia Wind Technology.

A.2.2 Technical working group meetings

The key insights from each technical working group meeting and any subsequent conversation we had with stakeholders are highlighted below.

TWG Meeting 1 (8 August 2022) — Summary of stakeholder feedback to consultation paper and the proposed assessment framework

At this meeting, the options that stakeholders proposed in submissions to our consultation paper, and the assessment criteria that will govern our approach to making a decision were discussed. Attendees all noted their agreement with the assessment criteria.

The majority of stakeholders who spoke indicated that both the minimum reactive current response capability level and the definition of response characteristics should be changed to better align the requirements to local needs, responses from other generators in the area and local fault characteristics.

OEMs, project developers and AEMO noted that the quantity of reactive response capability and how the response should be controlled needs to take account of fault characteristics, whether coincident frequency and voltage faults demand the need for reprioritisation of active power, and the behaviour of other generators who may also be contributing reactive

136 The statutory notices for each extension can be found on the project webpage: https://www.aemc.gov.au/rule-changes/efficient-reactive-current-access-standards-inverter-based-resources

137 The rule change process: a guide for stakeholders, June 2017, available here: https://www.aemc.gov.au/sites/default/files/201809/A-guide-to-the-rule-change-process-200617.PDF

power to manage the fault at the same time. These elements would be important to consider in making any changes.

TWG Meeting 2 (21 September 2022) — Input sought on Aurecon's preliminary results and the principles governing an appropriate reactive current response

Attendees provided valuable feedback on the formulation of the principles that should govern a reactive current response. In particular, a number of stakeholders noted that the principles should not introduce additional prescription that disallows adequate responses to complex, unbalanced faults that behave in unpredictable ways. For example, the rules should not inadvertently specify characteristics for how a reactive current response should behave.

The technical consultant — Aurecon — proposed a technically attractive solution to reformulate the reactive current standard to specify that generators inject or absorb a specific amount of total current. However, stakeholders considered that this solution would introduce a different form of complexity to generator-NSP negotiations and did not support this. This is because there is a well-established inverse relationship between reactive current and voltage disturbance but no well-understood relationship between total current and voltage -see Chapter 3 for further discussion of this proposal.

Aurecon also presented results proposing that response characteristics be reformulated to specify a time frame for when an adequate response should be delivered. Aurecon noted that these proposals would provide a better technical reflection of appropriate responses to unbalanced faults, which are the most common type of fault seen on the power system. AEMO noted that the delivery time standard can only be measured at the end of the fault, which may create a disincentive for generators to provide a fast response, which is also critical to ensure voltages stabilised as soon as practicable to maintain power quality outcomes for loads, and generator synchronisation.

TWG Meeting 3 (27 October 2022) — Input sought on possible options

This technical working group discussed how much reactive current capability should be sought, the characteristics that the reactive current response should have, how the response should behave after the fault clears, and the specific definitional clarifications that the rules should provide to support efficient negotiation of a generator performance standard.

At this meeting, OEMs noted that flexibility in the rules to allow lower levels of reactive current capability provision is more likely to support system security at least cost than a non-zero, positive reactive current capability standard. Most NSPs and AEMO noted that their preference would be for a higher, non-zero reactive current capability. One party noted that a higher MAS may lead to more conservative assessments of reactive current capability needs, especially if those assessments are being carried out by less experienced engineers.

A.2.3 Other stakeholder meetings

Outside of the TWG meetings, Commission staff also scheduled many bilateral discussions with stakeholders, such as the market bodies, OEMs, generation project developers, and the CRI and NSPs. The views expressed in these discussions broadly echoed the key theme of the need for this element of the access standards to support more flexibility for generators and NSPs to negotiate a pragmatic level of reactive current capability.

One point that was made in a number of bilateral discussions was that numeric prescription of both the reactive current capability that generators should provide, and how the response should behave is valuable. Leaving these numeric benchmarks out of the rules may see too much NSP discretion that would vary both by jurisdiction and the prior experience and knowledge of the connecting engineer(s) with whom proponents liaise. Some stakeholders also noted that the numeric benchmarks for response characteristics (i.e. rise time and commencement time under the proposed draft rules) provide a design criterion that they can aim for when tuning their equipment for a particular connection site.

Following the receipt of stakeholder submissions to the draft determination, the AEMC has conducted a number of one-on-one conversations on issues raised in submissions with Tesla, AEMO, Powerlink, Transgrid, TasNetworks, Kate Summers and Keith Frearson, Bo Yin, APD Engineering, Gridmo, Goldwind, Gridwise Energy Solutuions, the Energy Networks Association and 5 of its members, and a workshop with 28 CEC members on 30 March 2023. These meetings were used to ensure stakeholders were comfortable with changes to the draft, in response to stakeholder feedback, on:

- the level of the standard
- voltage commencement thresholds agreed outside the prescribed ranges
- definition of maximum continuous current
- definition of continuous uninterrupted operation
- implementation timeframes

B LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this final rule determination.

B.1 Final rule determination

In accordance with s. 102 of the NEL the Commission has made this final rule determination in relation to the rule proposed by Renewable Energy Revolution and the rule proposed by GE International Inc., Goldwind Australia, Siemens Gamesa Renewable Energy, Vestas Australia.

The Commission's reasons for making this final rule determination are set out in chapter 2.

A copy of the more preferable final rule is attached to and published with this final rule determination. Its key features are described in chapter 3.

B.2 Power to make the more preferable final rule

The Commission is satisfied that the more preferable final rule falls within the subject matter about which the Commission may make rules. The more preferable final rule falls within s. 34 of the NEL as it relates to:

- the operation of the national electricity system for the purposes of the safety, security and reliability of that system[138], and
- the activities of persons (including Registered participants) participating in the national electricity market or involved in the operation of the national electricity system[139]

B.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the more preferable final rule
- the rule change request
- submissions received during first and second round consultation for the rule change request
- the Commission's analysis as to the ways in which the more preferable final rule will or is likely to, contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[140]

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of Australian

138 Section 34(1)(a)(ii) of the NEL.

139 Section 34(1)(a)(iii).

140 Under s. 33 of the NEL, the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated council is now called the Energy Ministers Meeting.

Energy Market Operator (AEMO)'s declared network functions.[141] The more preferable final rule is compatible with AEMO's declared network functions because it would not affect those functions.

B.4 Making electricity rules in the Northern Territory

Test for scope of "national electricity system" in the NEO

Under the NT Act, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[142]

(a) the national electricity system

(b) one or more, or all, of the local electricity systems[143]

(c) all of the electricity systems referred to above.

Test for differential rule

Under the NT Act[144], the Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, a different rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[145] A differential rule is a rule that:

- varies in its term as between:
  - the national electricity system, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

A uniform rule is a rule that does not vary in its terms between the national electricity system and one or more, or all, of the local electricity systems, and has effect with respect to all of those systems.[146]

The Commission has determined to make a uniform rule as it does not consider that a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.

141 Section 91(8) of the NEL.

142 Clause 14A of Schedule 1 to the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

143 These are specified Northern Territory systems, listed in schedule 2 of the NT Act.

144 National Electricity (Northern Territory) (National Uniform Legislation) Act 2015 (**NT Act**).

145 Clause 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

146 Clause 14 of Schedule 1 to the NT Act, inserting the definitions of "differential Rule" and "uniform Rule" into section 87 of the NEL as it applies in the Northern Territory.

B.5 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may recommend to the Energy Ministers Meeting that new or existing provisions of the NER be classified as civil penalty provisions.

The more preferable final rule does not amend any clauses that are currently classified as civil penalty provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the Energy Ministers Meeting that any of the proposed amendments made by the more preferable final rule be classified as civil penalty provisions.

B.6 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the Energy Ministers Meeting that new or existing provisions of the NER be classified as conduct provisions.

The more preferable final rule does not amend any rules that are currently classified as conduct provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the Energy Ministers Meeting that any of the proposed amendments made by the more preferable final rule be classified as conduct provisions.

C WHY REACTIVE CURRENT INJECTION/ABSORPTION IS DESIRABLE DURING FAULTS

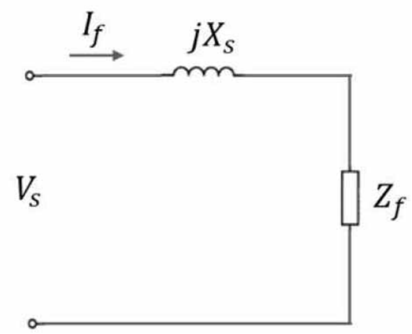
When a fault occurs in the power system, voltages rapidly change, in most cases reducing. This voltage change is greatest at the location of the fault and reduces with electrical distance from the fault. Plant and equipment in the power system are designed to operate within a specific range of voltage, and may not be able to inject as much active power into the system, or lose synchronisation and disconnect when the voltage is outside of this range. This includes loads tripping and generators disconnecting or experiencing damage, among other effects. These outcomes, which are undesirable in themselves, will change the supply and demand balance in the power system and result in frequency disturbances.

In the same way that active power affects frequency, reactive power affects voltages, albeit on a locational basis. If reactive power is injected when the network is in equilibrium, then voltages will rise, and vice versa if reactive power is absorbed. Consequently, the provision of reactive power, through reactive current during faults, reduces the size of the voltage change, and reduces its propagation in the power system (noting that no amount of reactive current will improve voltages near a bolted fault). This has the effect of reducing the amount of equipment in the power system that experiences large changes in voltage and the negative outcomes associated with doing so.

C.1 Impact of reactive current on bus voltages during a fault

The simplified equivalent circuit for a short circuit is shown below:

Figure C.1: Simplified equivalent circuit for a short circuit



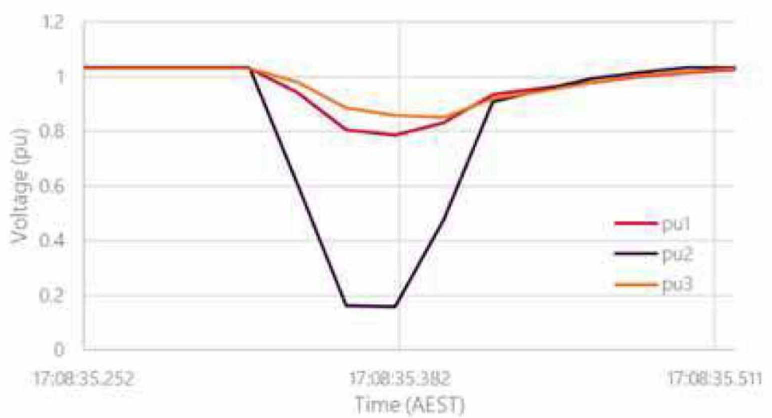
Source: AEMC

Note: V_S is the upstream voltage (V), X_S is the upstream short circuit impedance, Z_f is the fault impedance and I_f is the fault current (A). Note that X_S is represented here as a pure reactance to reflect the typical characteristics of a transmission network and illustrate that the fault current is mostly reactive (or capacitive) in nature.

In the theoretical three-phase bolted fault, the short circuit impedance is zero and voltage at the fault location will also tend towards zero . However, real faults are typically not quite so severe and there is some non-zero short circuit impedance. Most real faults also tend to be asymmetrical, e.g. phase-to-earth or phase-to-phase.

In any case, the voltage of the faulted phases at the fault location is generally quite low. For example, the figure below shows the voltages after a severe phase-to-earth fault in South Australia showing the voltage of the faulted phase drop to 0.16 pu (measured at a substation electrically nearby to the fault location):

Figure C.2: Voltages at Torrens Island during busbar trip

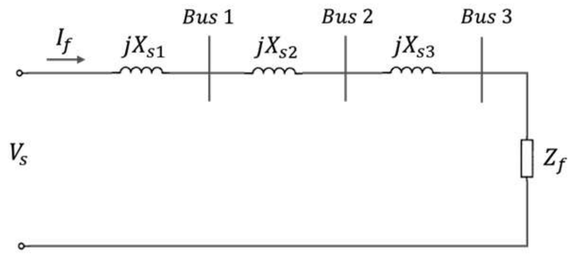


Empty Para: remove or apply correct style

Source: AEMO

For illustrative purposes, the equivalent circuit can be extended to show additional buses farther away from the fault location:

Figure C.3: Simplified equivalent circuit for a short circuit, with multiple buses



Source: AEMC

The voltage at each bus can be calculated by a simple voltage divider:[147]

147 Refer to AEMO reviewable operating incident report https://aemo.com.au/-media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/final-report-torrens-island-275-kvwest-busbar-trip.pdf?la=en

Figure C.4: Voltage divider equations

$$V_{bus\ 1} = \frac{Z_f + jX_{s2} + jX_{s3}}{j(X_{s1} + X_{s2} + X_{s3}) + Z_f} V_s$$

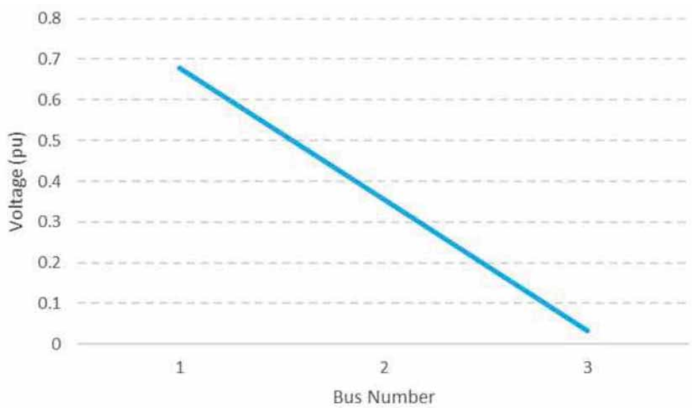
$$V_{bus\ 2} = \frac{Z_f + jX_{s3}}{j(X_{s1} + X_{s2} + X_{s3}) + Z_f} V_s$$

$$V_{bus\ 3} = \frac{Z_f}{j(X_{s1} + X_{s2} + X_{s3}) + Z_f} V_s$$

Source: AEMC

As an example, if $X_{S1}=X_{S2}=X_{S3}=0.1$ and $Z_f=j0.01$, then the voltages at each bus are:

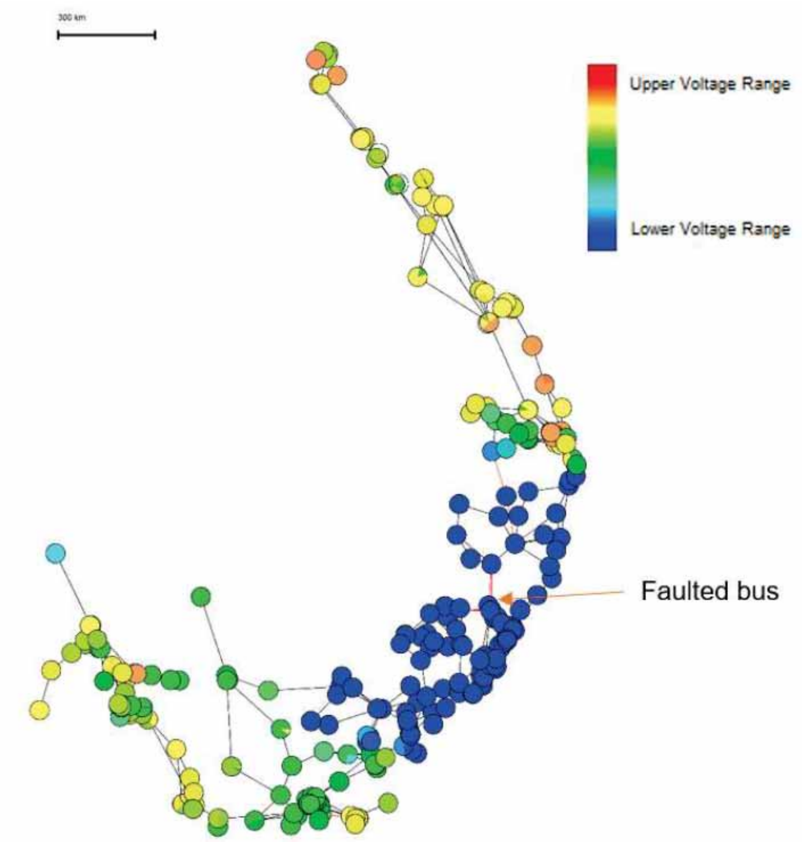
Figure C.5: Bus voltages during fault



Source: AEMC

It can be observed that while the voltage at the faulted bus is typically very low, the voltages at upstream buses are generally much higher. Across a wide area, many distant nodes may not even experience a voltage dip even during the most severe faults, e.g. a simulated threephase fault in the NSW transmission backbone:

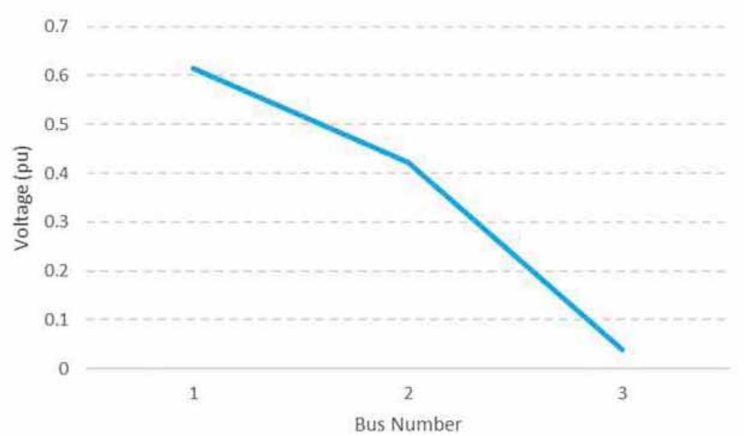
Figure C.6: Transmission bus voltages during fault



Source: AEMC

Injection of reactive current during a fault is equivalent in many ways to increasing the fault current delivered to the fault, or reducing the equivalent short circuit impedance (X_S). For example, if a reactive current injection in Bus 2 reduces X_{S1} to 0.05, then this has the effect of supporting voltages at Bus 2:

Figure C.7: Bus voltages during fault, with reactive current injection



Source: AEMC

Therefore, one of the key drivers for reactive current injection during a fault is to support bus voltages (though not necessarily near the faulted bus). In this narrow context, there is no such concept as *too much* reactive current injection during a fault (provided that it is injected proportional to voltage).

C.2 Why should voltages be supported during a fault?

From a power quality perspective, voltage sags (or dips) are defined by IEEE 1159 and IEC 61000-4-30 as a *"decrease in rms voltage between 0.1 pu and 0.9 pu for durations from 0.5 cycles (10 ms) to 1 min"*. Voltage sags as a result of faults would be classified as instantaneous sags between 0.5 cycles and 30 cycles (10 - 600 ms). Voltage sags due to transmission network faults have long been observed to cause loads to trip (called "load rejection"), which is primarily due to the following voltage sensitivities in loads:

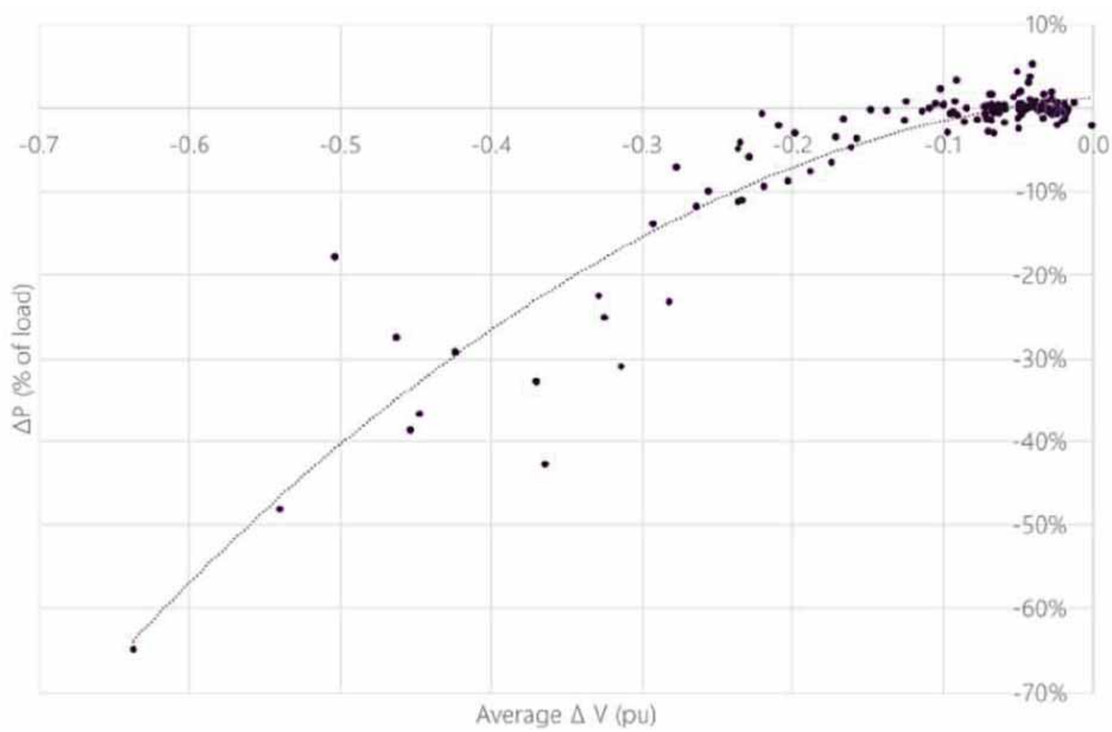
- AC contactors are sensitive to voltage sags and can drop out during faults, which is pertinent to industrial process control systems using contactors for motor control
- Electronic equipment can be sensitive to voltage sags, e.g. computers can switch off and reset during sags, and power electronics can trip during long duration and severe faults
- Compressor motors (e.g. on air conditioners) can stall for longer duration and severe voltage sags

An AEMO analysis of high-speed data of several Queensland feeders found the following:

"Load disconnects following voltage disturbances. For residential feeders, a 0.5 pu fault was observed to lead to around 8% of load disconnecting, while for commercial/light industrial feeders, a 0.5 pu fault led to around 40% of load disconnecting, with 25% of the load remaining disconnected for longer than five seconds. This confirms the existing understanding that commercial loads may be more sensitive to disconnection when exposed to voltage dips, compared with residential loads (although there is likely to be significant diversity, and the loads monitored in this analysis may not be generally representative)."

From the same report, it was also observed that the volume of load tripping is related to the voltage sag magnitude in a non-linear manner, e.g. data from a commercial distribution feeder:

Figure C.8: Queensland commercial distribution feeder load tripping by voltage sag



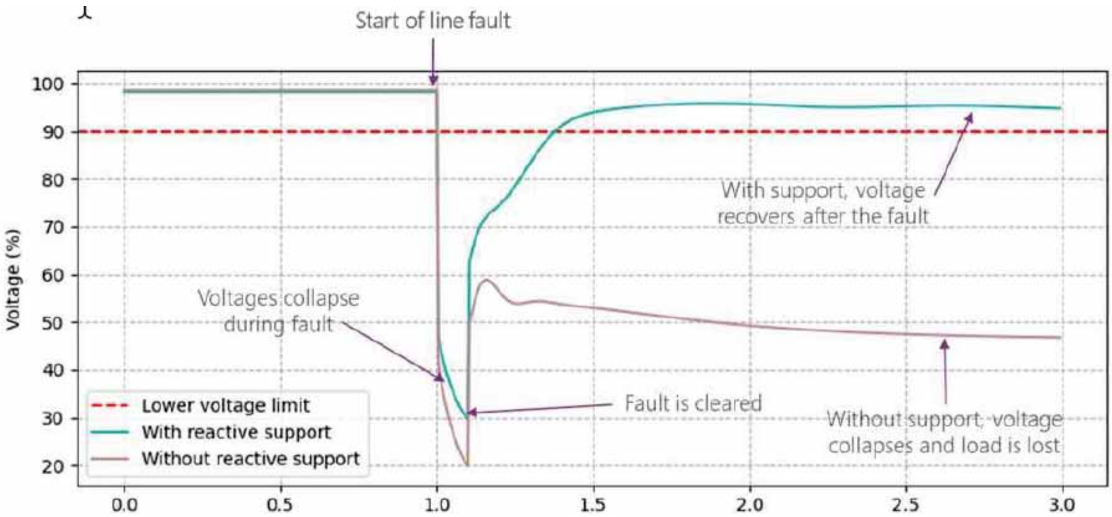
Source: AEMC

Reactive current injection during faults can help prevent some load tripping by supporting network voltages, although this contribution may be limited in the vicinity of the fault location. While there are benefits from supporting voltages through reactive current injections, it is generally accepted that a nearby fault can (and will) cause load tripping.

C.3 Post-fault voltage stability

Bus voltages may not recover immediately after a fault is cleared. This can occur because of the load composition in the area around the fault location. For example, if there is a significant volume of induction machines in the area, the voltage sag during the fault could cause the machines to draw more reactive power (or even stall), thus depressing voltages further. Without additional reactive current injection, the voltage may not recover and collapse post-fault.

Figure C.9: Bus voltage with and without reactive support



Source: AEMC

The requirement for post-fault dynamic reactive support is locational and largely dependent on the load composition and strength of the system (e.g. industrial areas located in a weaker part of the grid with high upstream source impedance Xs are more likely to require post-fault dynamic reactive support).

C.4 Minimum fault current for protection relays

Reactive current injections from IBR plant are equivalent to fault currents from synchronous machines, and contribute to the overall fault current delivered to the fault location. In a future where synchronous generators have retired, there is a concern that there is insufficient fault current for protection relays to operate correctly, especially in weaker parts of the grid.

Reactive current injections will help to mitigate this, but only if generators are located in areas where insufficient fault current is an issue. The converse can also be true, i.e. reactive current injections could exacerbate an area with too much fault current (exceeding equipment fault ratings), though this would be rare in the NEM.

The NSPs also have an obligation to ensure that protection relays operate correctly, whether this is via procurement of system strength services (to increase the fault level) or modification of protection schemes to operate at lower fault levels.

C.5 What can happen when there is too much reactive current injection?

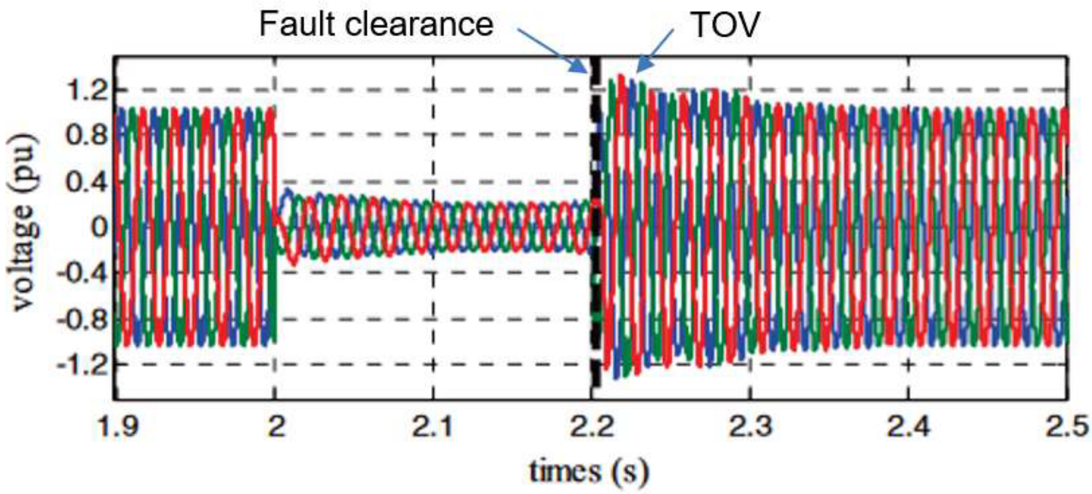
Generally speaking, reactive current injection during a fault (and post-fault) is good for voltage support and recovery, but there are circumstances when you can have too much.

i) Post-fault temporary over voltages

In weaker parts of the grid (e.g. distribution network) and areas with significant penetration of IBR within close proximity, temporary overvoltages (TOV) can occur post-fault due to excessive reactive current injection during the control delay in handover from low voltage ride through (LVRT) mode to normal plant control mode. The TOV can cause plant to enter high voltage ride through (HVRT) mode.

This is a phenomenon that has also been observed in HVDC systems and may become more prevalent in time with higher penetrations of IBR connecting in weak areas.

Figure C.10: Temporary over voltage



Source: Saad and Dennetiere (2019)[148]

ii) LVRT re-triggering (or cycling) during shallow faults

Excessive reactive current injections during shallow faults can cause local inverter terminal voltages to rise high enough to exit LVRT mode before the fault is cleared. As the fault is still present, the voltages fall again and the plants enter back into LVRT mode. This cycling will occur until the fault is cleared.

This issue was mentioned in the rule change request by the wind turbine OEMs, as well as submissions to the consultation paper by Windlab and Bo Yin.[149]

iii) Withdrawal of active power during shallow faults

In order to meet high reactive current requirements during shallow faults (where the voltage at the inverter terminals may be materially higher than the voltage at the connection point), IBR proponents may be incentivised to design the control system to withdraw their active current injection to boost their reactive current output.

148 H. Saad and S. Dennetière, "Study on TOV after fault recovery in VSC based HVDC systems," 2019 IEEE Milan PowerTech, 2019, pp. 1-6, doi: 10.1109/PTC.2019.8810479

149 Submissions to the consultation paper: Windlab, p. 4; Bo Yin, pp. 7-10

In such circumstances, the additional reactive current is typically not very useful to the grid. In fact, the withdrawal of active power can lead to frequency disturbances when IBR enter LVRT mode (refer to the TasNetworks submission on this issue already occurring in Tasmania).[150]

Moreover, in distribution networks with low X/R ratios (and greater coupling between active power and voltage), the prioritisation of reactive power and simultaneous withdrawal of active power may only be marginally more beneficial to supporting voltages than not withdrawing active power.

iv) Overvoltages on unfaulted phases

During unbalanced faults, reactive current injections into unfaulted (healthy) phases may cause overvoltages. This is typically mitigated by negative sequence current control strategies in the inverters. Doubly-fed induction generators (DFIG) are also intrinsically able to absorb negative sequence currents, which can be beneficial for preventing overvoltages on unfaulted phases.

150 Tasnetworks, submission to consultation paper, p.4.

D ALTERNATIVE FORMULATIONS CONSIDERED

In the process of developing its draft rule position on the reactive current capability standard, the Commission considered two alternative formulations for this element of the MAS:

- principles-based
- total-current-based

Our consideration of these formulations is outlined below.

D.1 A principles-based standard may make connection assessments less objective

Given the sheer variety of different fault scenarios, grid characteristics, and IBR system topologies, the Commission considered moving away from a numerical MAS to one based on principles. On a surface level, this would appear to provide the flexibility that the OEMs' proposal seeks to embed in the rules, while also ensuring that NSPs have the tools available to require IBR to provide reactive support. However, discussions with stakeholders revealed two key potential issues in the practical application of this approach:

- When compared to a numerical standard, principles have a much larger scope for interpretation by the individual that is assessing against them. This may result in a large variance in interpretation across different engineers and NSPs, and reduce transparency and predictability in the connection process.
- OEMs noted that numerical standards form a useful benchmark when they are optimising and tuning their equipment for the Australian market. Project developers echoed this sentiment, noting that project connection studies may have to go through more iterations if there is not a numerical standard that proponents are optimising their projects to meet.

We acknowledge the validity of these concerns and consider that they are reason enough not to pursue a principles-based standard in the draft rule.

D.2 A total-current-based standard is technically appealing but has some key practical drawbacks

Moving to a standard that is based on total current addresses several of the technical drawbacks of reactive current and was proposed by Aurecon as part of their investigation. Total current refers to the total amount of current that is sent out by the generating system, and is the sum of the active, reactive, positive-sequence, and negative-sequence currents.

Throughout the course of the rule change process, stakeholders and Aurecon identified several potential benefits of a total current standard over a reactive current standard. These and accompanying stakeholder feedback and Commission views are discussed below.

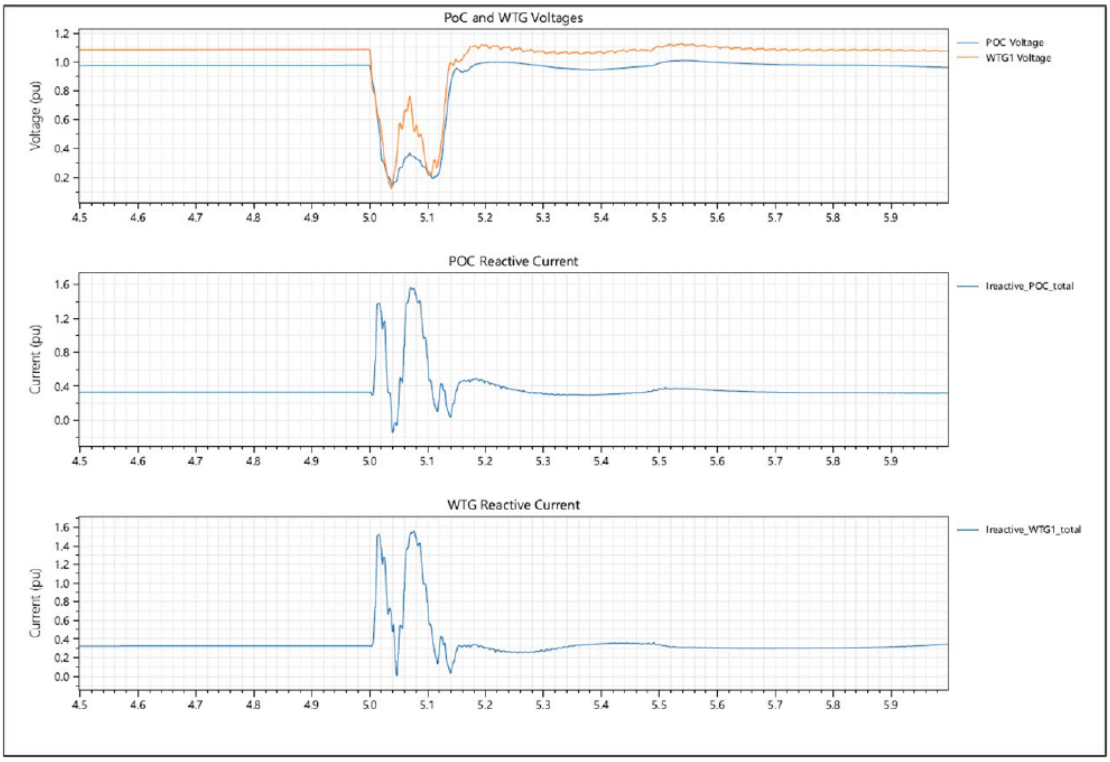
D.2.1 Reactive current is not a directly measurable quantity

Reactive current is a mathematically derived quantity reflecting the component of current (a physical quantity) that contributes to reactive power. There are a number of methods for calculating reactive current and while it has been observed that results are fairly consistent across different methods for balanced (symmetrical) voltage disturbances, material differences are observed during unbalanced scenarios. Unfortunately, no one method is applicable for all fault scenarios, which can create ambiguity in the connection process. A formulation based on total current does not have this ambiguity as it is a directly measurable physical quantity. Defining reactive current is explored in more detail in section 3.4.3.

D.2.2 Reactive current provision during unbalanced faults can be difficult to assess

During unbalanced faults, positive sequence reactive current injection can be highly variable (including periods of absorption) and often difficult to assess. This issue was investigated in detail by Aurecon through a series of simulation studies, showing ambiguities in the quality of a plant's response when measured through positive sequence reactive current that is open to interpretation. For example, consider the response to an unbalanced fault in Figure D.1 below:

Figure D.1: Simulated reactive current injection at the POC and WTG terminals, in response to a fault



Source: Aurecon, Advice on reactive current access standards, p. 32

The positive sequence reactive current response at the POC in Figure D.1 illustrates the potential ambiguities in assessment, e.g.

- What is the volume of the response? Is it the magnitude of the first peak or second peak or another magnitude?
- What is the rise time? Is it the rise time of the first or second peak?
- What is the settling time? It could be argued that this response never settles until the fault is cleared.
- How should the reactive current absorption at t = 5.04 seconds be treated? Is this treated as a non-compliance?

Distortions in the voltage waveform during a fault can also cause similar issues in reactive current response and interpretation.

Stakeholders acknowledged that the standard was originally written with balanced faults in mind and the use of reactive current to assess unbalanced faults can pose an issue. However, many stakeholders viewed this as a manageable problem that did not justify a complete overhaul of the formulation.

D.2.3 Reactive current priority may not be appropriate for low X/R ratio areas of the grid

This issue was first raised by RER in its rule change request,[151] noting the greater level of coupling between active power and voltage in highly resistive (or low X/R ratio) areas of the grid, e.g. distribution networks. Though reactive current itself is not the issue in this case, the form of the standard tacitly assumes a reactive (Q) priority in the inverter control system (i.e. a k-factor that provides a reactive current response proportional to voltage), which may come at the expense of active power withdrawal. This is rightly viewed as inappropriate for low X/R ratio connection points where active power may have just as material a contribution to voltage as reactive power.

This is also an issue for synchronous machines (and grid-forming inverters), which can be characterised as voltage sources with inherent fault current contributions that are a function of internal (machine), external (grid) and fault impedances. There are scenarios where a synchronous machine may not provide a compliant reactive current response, for example, at low X/R ratio connection points or during resistive faults.

D.2.4 Total current is a technically attractive alternative to reactive current

The preliminary simulation studies performed by Aurecon, as well as the stakeholder feedback, indicated that the total current formulation has features that overcome the limitations of reactive current, for example:

- Total current is a physical measurable quantity and does not need to be calculated
- Total current exhibits more stable behaviour (and is thus easier to assess) under unbalanced fault conditions
- Total current does not unnecessarily incentivise Q priority

151 RER, NER Rule change request proposal, 2 April 2019, pp. 2-3

The Aurecon studies suggested two preliminary levels for the total current standard, one based on full pre-disturbance output (110% of total current) and another based on a low pre-disturbance output (70% of total current).

D.2.5 But stakeholders are comfortable with reactive current and would prefer tweaks to the existing standard

The majority of stakeholders consulted were not convinced that the formulation of the standard had to be changed. There was general agreement that total current was technically attractive, but there was discomfort with introducing a completely new formulation that has not been widely tested, with the attendant risk of unintended consequences.[152]The key issues raised include:

- A total-current-based standard decouples the controlled quantity (total current) with the objective (controlling voltage levels). This contrasts with a reactive-current-based standard, as reactive current directly influences voltage levels.
- The proposed formulation of the total current standard includes different levels of capability required at different active power levels. This would introduce additional complexity and prescription into the standard, two factors that all stakeholders have expressed a keen desire to reduce throughout this process.
- The industry is familiar with the reactive-current-based standard after operating under it since 2018. Many TWG members expressed nervousness that this reformulation could introduce unintended consequences.

In assessing a reformulated standard based on total current, the Commission considers that the practicalities of implementing such a standard outweigh the technical benefits, and as such we have maintained the reactive current formulation of the MAS in the draft rule.

152 AEMC reactive current technical working group 2, 21 October 2022