Department of Energy and Economic Diversification

GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Meeting Agenda

Meeting Title:	Pilbara Advisory Committee (PAC)
Date:	Thursday 17 September 2026
Time:	1:30 PM – 3:30 PM
Location:	Online

#	Item	Responsibility	Type	Duration
1	Welcome and Agenda • Conflicts of interest • Competition Law	Chair	Noting	3 min
2	Meeting Apologies/Attendance	Chair	Noting	3 min
3	Minutes of Meeting 2025_07_23 Published 30 July 2026	Chair	Noting	2 min
4	PAC Action Register	Chair	Noting	2 min
5	Pilbara Advisory Committee review	Chair	Discussion	45 min
6	EPNR Project – Update and Tranche Zero PNR Amending Rules • Future Working Group meetings • Proposed PNR Amending Rules (Tranche Zero)	DEED/ISO	Discussion	60 min
8	General Business	Chair	Discussion	5 min
	Next meeting: 12 November 2026 at 1:30pm			

Please note, this meeting will be recorded.

Competition and Consumer Law Obligations

Members of the PAC (**Members**) note their obligations under the *Competition and Consumer Act 2010* (**CCA**).

If a Member has a concern regarding the competition law implications of any issue being discussed at any meeting, please bring the matter to the immediate attention of the Chairperson.

Part IV of the CCA (titled "Restrictive Trade Practices") contains several prohibitions (rules) targeting anti-competitive conduct. These include:

(a) **cartel conduct**: cartel conduct is an arrangement or understanding between competitors to fix prices; restrict the supply or acquisition of goods or services by parties to the arrangement; allocate customers or territories; and or rig bids.

(b) **concerted practices**: a concerted practice can be conceived of as involving cooperation between competitors which has the purpose, effect or likely effect of substantially lessening competition, in particular, sharing Competitively Sensitive Information with competitors such as future pricing intentions and this end:

- a concerted practice, according to the ACCC, involves a lower threshold between parties than a contract arrangement or understanding; and accordingly; and
- a forum like the PAC is capable being a place where such cooperation could occur.

(c) **anti-competitive contracts, arrangements understandings**: any contract, arrangement or understanding which has the purpose, effect or likely effect of substantially lessening competition.

(d) **anti-competitive conduct (market power)**: any conduct by a company with market power which has the purpose, effect or likely effect of substantially lessening competition.

(e) **collective boycotts**: where a group of competitors agree not to acquire goods or services from, or not to supply goods or services to, a business with whom the group is negotiating, unless the business accepts the terms and conditions offered by the group.

A contravention of the CCA could result in a significant fine (up to $500,000 for individuals and more than $10 million for companies). Cartel conduct may also result in criminal sanctions, including gaol terms for individuals.

Sensitive Information means and includes:

(a) commercially sensitive information belonging to a Member's organisation or business (in this document such bodies are referred to as an Industry Stakeholder); and

(b) information which, if disclosed, would breach an Industry Stakeholder's obligations of confidence to third parties, be against laws or regulations (including competition laws), would waive legal professional privilege, or cause unreasonable prejudice to the Coordinator of Energy or the State of Western Australia).

Guiding Principle – what not to discuss

In any circumstance in which Industry Stakeholders are or are likely to be in competition with one another a Member must not discuss or exchange with any of the other Members information that is not otherwise in the public domain about commercially sensitive matters, including without limitation the following:

(a) the rates or prices (including any discounts or rebates) for the goods produced or the services produced by the Industry Stakeholders that are paid by or offered to third parties;

(b) the confidential details regarding a customer or supplier of an Industry Stakeholder;

(c) any strategies employed by an Industry Stakeholder to further any business that is or is likely to be in competition with a business of another Industry Stakeholder, (including, without limitation, any strategy related to an Industry Stakeholder's approach to bilateral contracting or bidding in the energy or ancillary/essential system services markets);

(d) the prices paid or offered to be paid (including any aspects of a transaction) by an Industry Stakeholder to acquire goods or services from third parties; and

(e) the confidential particulars of a third party supplier of goods or services to an Industry Stakeholder, including any circumstances in which an Industry Stakeholder has refused to or would refuse to acquire goods or services from a third party supplier or class of third party supplier.

Compliance Procedures for Meetings

If any of the matters listed above is raised for discussion, or information is sought to be exchanged in relation to the matter, the relevant Member must object to the matter being discussed. If, despite the objection, discussion of the relevant matter continues, then the relevant Member should advise the Chairperson and cease participation in the meeting/discussion and the relevant events must be recorded in the minutes for the meeting, including the time at which the relevant Member ceased to participate.

Department of Energy and Economic Diversification
GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Agenda Item 4: PAC Action Register

Pilbara Advisory Committee (PAC) Meeting 2026_09_17

Shaded	Shaded action items are actions that have been completed since the last PAC meeting. Updates from last PAC meeting provided for information in RED.
Unshaded	Unshaded action items are still being progressed.
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

Item	Action	Responsibility	Meeting Arising	Status
4/2026	DEED to consider early rule changes (Package 0) to address ISO model access issues. This action relates to item 5. EPNR UPDATE – NSP TO NSP FRAMEWORK arising from discussion in the 21 May 2026 PAC meeting.	DEED	2026_05_21	Closed. This will be included in Tranche Zero and outlined in Item 6.
5/2026	Powering WA to provide a further update to the PAC on CEFC funding allocation when additional information becomes available. This action relates to item 6. PAC ACTION REGISTER presentation by Ms Barrie in the 21 May 2026 PAC meeting.	DEED	2026_05_21	Open – No further update

Item	Action	Responsibility	Meeting Arising	Status
6/2026	DEED to consider the need for an additional PAC meeting following further working group progress. This action relates to item 7. GENERAL BUSINESS raised by Ms O'Brien at the 21 May 2026 PAC meeting to discuss outage-related reforms, noting the complexity of the issues and the limited time available during standard PAC meetings.	DEED	2026_05_21	Closed. No additional PAC meetings for 2026 are anticipated at this stage.

Department of Energy and Economic Diversification
GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Agenda Item 5: Pilbara Advisory Committee Review

Pilbara Advisory Committee (**PAC**) Meeting 2026_09_17

1. Purpose

The purpose of this item is to discuss the effectiveness of the PAC in performing its intended role and to identify whether any changes are required to ensure that the PAC provides effective advice to the Coordinator regarding the evolution or the development of the Pilbara regime.

2. Recommendation

That the PAC:

1. discusses the questions listed in section 4 of this paper; and
2. considers its effectiveness in meeting its objectives and whether any changes to the PAC's role, priorities, membership or operating arrangements would improve its effectiveness.

3. Background

- The PAC was first convened on 4 May 2022. There has not subsequently been a review of the PAC's effectiveness or operating arrangements.
- Rule A2.3.1 of the Pilbara Networks Rules outlines that the PAC is convened to provide advice to the Coordinator:
  - on Rule Change Proposals and Procedure Change Proposals; and
  - on matters concerning, and the Coordinator's plans for, the evolution and development of the Rules.
- Since that PAC was established, two Rule Change Proposals have been progressed. Accordingly, much of the PAC's activity related to broader matters concerning the evolution and development of the Pilbara regulatory framework, rather than consideration of formal Rule Change Proposals.
- Pursuant to clause 2.3 of the PAC constitution, PAC Members are required to act in the best interests of the operation, management, security and reliability of the interconnected Pilbara system and other Pilbara networks.
- After more than four years of operation, it is timely to consider whether the PAC's current role, work program and operating arrangements are enabling it to provide effective advice to the Coordinator, and whether a different approach would better support the future evolution and development of the Pilbara regime.

4. Discussion Questions

1. In the absence of frequent Rule or Procedure Change Proposals, what role should the PAC play in identifying, considering and advising on emerging issues to support the future evolution and development of the Pilbara regime?

2. Do PAC meetings provide sufficient opportunity for substantive discussion and development of effective advice?

3. Could changes to agenda-setting, meeting papers, meeting format or the way meetings operate improve the quality of PAC deliberations and advice?

4. Does the frequency of the PAC meetings support its effective advice, or should the meeting schedule be driven more directly by the work program and matters requiring PAC advice?

5. Is there anything else that can be done to improve the effectiveness of the PAC operation and its deliberations?

Department of Energy and Economic Diversification
GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Agenda Item 6: EPNR Project Update and proposed PNR Amending Rules (Tranche Zero)

Pilbara Advisory Committee (**PAC**) Meeting 2026_09_17

1. Purpose

The purpose of this item is to provide an update to the PAC on the EPNR Project and present an overview of the Tranche Zero Exposure Draft (**Attachment 1**).

2. Recommendation

That the PAC:

1. Note the EPNR Project update.
2. Discuss and provide feedback on the Tranche Zero Exposure Draft in advance of the public consultation.

3. Background

Project Update

- Since the last PAC meeting on 23 July 2026, no further EPNR Working Group meetings have been held.
- Three EPNR Working Group meetings have been scheduled which will progress the outage coordination and ESS cost allocation frameworks:
  - Wednesday, 16 September 2026
  - Wednesday, 14 October 2026
  - Wednesday, 4 November 2026

Tranche Zero Exposure Draft

- Since the last PAC meeting on 23 July 2026, the Tranche Zero Exposure Draft (**Attachment 1**) has been prepared.
- Tranche Zero addresses 24 issues. These are outlined in Table 1, together with a summary of PAC and EPNR Working Group involvement in the development of the draft Rules.

Table 1 – Summary of Tranche Zero

Schedule	Topic	PAC / WG involvement
1	Amending rules to rename Essential System Services (ESS)	Per implementation plan
2	Suspension of ISO Planning 2027 deliverables	Discussed at PAC and WG
3	Head of power for manual load shedding	Per implementation plan

4	Opening CPC Facility Class by not requiring non-compliance	Per implementation plan
5	Creating a requirement for a reduced NWIS model, which is readily available to connection applicants	Discussed at PAC and WG
6	Remove the requirement for the small use customer and contestable customer representatives on the PAC to be nominated by the Minister	Not discussed, introduced for consistency with changes to the Electricity System and Market Rules
Changes to the HTR		
7	Updated WA Voltage and Frequency Regulation and review of clause 2.2.2(c) (varying voltage operating standard by agreement)	Draft rules shared with WG
8	Review of HTR cl 3.7 (Requirements for the connection of storage)	Draft rules shared with WG
9	Inverter Dynamic Performance	Draft rules shared with WG
10	Frequency control dead band	Draft rules shared with WG
11	Disturbance monitoring and synchrophasors	Draft rules shared with WG
12	Changes to Figure 3.3 and to the reactive power capability of inverter-based generating units, to ensure HTR requirements are technology agnostic	Draft rules shared with WG
13	Treatment of Ambient Temperatures	Draft rules shared with WG
14	Monitoring and control requirements	Draft rules shared with WG
15	Fault Level Requirements and Equipment Ratings	Draft rules shared with WG
16	Adequacy of requirements for system restart arrangements	Draft rules shared with WG
17	Interaction between the HTR and CPC rules in the PNR	Draft rules shared with WG
18	Update CFCTs to reflect system changes and approved derogations	Draft rules shared with WG
19	Special Protection Schemes	Draft rules shared with WG
20	Overall review of referenced standards	Draft rules shared with WG

21	Replace references to 'ancillary services' with 'essential system services'	Draft rules shared with WG
22	Clarification of 'active power output' in cl. 3.3.4.4(e)(1)	Draft rules shared with WG
23	Correcting definition of 'point of common coupling'	Draft rules shared with WG
24	Introducing requirement to provide EMT models	Discussed at WG

- Table 2 provides further information on the issues highlighted in Table 1, which have been developed further following PAC and EPNR Working Group discussions.

Table 2 – Supporting information on selected issues

Schedule	Supporting information
2	Following discussion at the previous PAC meeting, Tranche Zero includes Amending Rules to suspend the ISO's 2027 planning deliverables. Options and proposals for long term planning functions will be addressed in a later Consultation Paper.
5	Following discussion at PAC, Amending Rules have been developed to establish the following framework: a. Existing and prospective NSPs must provide an unredacted power system model to the ISO for the ISO's use, which will not be released externally. b. Existing NSPs must also provide a reduced model, with confidential information removed and an explanation of the basis for its removal. c. The reduced model must be suitable for access and connection purposes, allowing the ISO to make the information in the model available to existing NSPs and access seekers. d. A procedure will specify the requirements of the model to be suitable for access and connection purposes. e. The ISO may determine that a submitted model does not meet the applicable requirements, in which case the relevant participant must remedy the model. f. Prospective NSPs seeking access to the model must register in an appropriate capacity, ensuring they are subject to the requirements governing use of the model and are required to provide their own model to the ISO.
6	To align with the amended provisions for the Market Advisory Committee, the Amending Rules remove the requirement for the Minister to nominate customer representatives to the PAC.
24	An Amending Rule has been prepared to clarify that generators have an ongoing obligation to provide models to their NSP in accordance with the requirements specified in the Power System Modelling Procedure.

- The HTR Working Group provided feedback on whether certain HTR Amending Rules should be subject to grandfathering arrangements. The grandfathering approach adopted in the Tranche Zero Exposure Draft is summarised in Table 3.

Table 3 – HTR grandfathering arrangements

Schedule	Grandfathering approach
8 – Storage works core technical rules	No grandfathering arrangements are proposed. However, exemptions may be available having regard to the feasibility of retrofitting equipment.
12 – Reactive power capability	The drafting provides that the technical standards applying at the time the access contract was executed continue to apply.
12 – Monitoring/control of small generating units	The drafting applies the new requirements only to equipment installed after commencement.
20 – Fault level withstand ratings	The drafting applies the new requirements only to “new equipment”, with existing equipment therefore unaffected.

4. Next Steps

- The EPNR Working Group will develop proposed outage coordination and ESS cost allocation frameworks for inclusion in an EPWA Consultation Paper.
- Following consideration of any feedback from the PAC, the Tranche Zero Exposure Draft will be published for a four-week public consultation period.

5. Attachments

1. Tranche Zero – Exposure Draft

EPNR TRANCHE 0: EXPOSURE DRAFT

PROPOSED PILBARA NETWORKS RULES (PNR) AMENDING RULES

Explanatory Note for Exposure Draft of the Tranche 0 Proposed PNR Amending Rules:

This exposure draft covers the initial tranche of changes resulting from the Evolution of the Pilbara Network Rules (EPNR) project. It contains proposed Amending Rules to:

- Rename ESS categories, replacing "FCESS" ("Frequency Control Essential System Service") with "Regulation", and "SRESS" ("spinning reserve Essential System Service") with "Contingency Reserve Raise".
- Suspend ISO LT Planning functions due in 2027.
- Require the ISO to develop a manual load shedding list.
- Remove non-compliance as an eligibility requirement for becoming a CPC Facility.
- Allow the ISO to provide prospective new connections to the NWIS with an appropriate version of the Power System Model.
- Remove the requirement for the Minister to nominate small use and large use contestable customer representative positions on the Pilbara Advisory Committee.
- Update the Harmonised Technical Rules (HTR) in line with drafting instructions provided by, and through discussions with the HTR Workstream of the Evolution of the Pilbara Networks Rules Working Group

Following industry consultation, the proposed Amending Rules in this exposure draft will be submitted to the Minister for Energy and Decarbonisation for making and gazettal.

The Department of Energy and Economic Diversification (DEED) is seeking stakeholder feedback on this exposure draft by **5:00 PM (WST) on date**. Feedback can be sent to energymarkets@deed.wa.gov.au.

Mark-up Colour guide:

Text in black	Pilbara Network Rules dated 18 July 2025 and assumed to be in force at the time the Amending Rules are proposed to commence.
Text in red - underlined ~~and strikethrough~~	Amendments proposed under EPNR Tranche 0

Contents

Schedule 1: Amending Rules to rename ESS

Explanatory Note

Review outcome 3.1 of the EPNR Implementation Plan determined that the existing two categories of ESS would be retained and that:

- "FCESS" service will be renamed "Regulation", and
- "SRESS" service will be renamed "Contingency Reserve Raise".

This schedule contains the proposed changes to implement this renaming and includes related changes to improve consistency and correct minor errors.

…

8 Glossary

…

Administered Secondary ~~FCESS~~ Regulation Price: Means the price published under rule 206(3).

…

~~**Alternative SRESS Procedure**: Subject to rule 73, means the Procedure made under rule 216(c).~~

…

Contingency Reserve Raise: Is defined in rule 213.

Contingency Reserve Raise Standard: Is defined in ~~rule 210~~ rule 211.

CRR Payment Share: Is defined in rule 229(1)(f).

CRR Payment Threshold: Is defined in rule 229(1)(a).

CRR Provider: Is defined in rule 213.

…

Disable: In relation to a~~n FCESS~~ Regulation Provider, means to call on or Direct the ~~FCESS~~ Regulation Provider to stop providing ~~FCESS~~ Regulation.

…

Enable:

a) in relation to a Generating Unit — means to start, or procure the starting of, the Generating Unit; and

b) in relation to a~~n FCESS~~ Regulation Provider — means to call on or Direct the ~~FCESS~~ Regulation Provider to start providing ~~FCESS~~ Regulation.

…

Essential System Service: Means a service, including ~~FCESS~~ Regulation and ~~SRESS~~ Contingency Reserve Raise, that is required to achieve the objectives in rule 199 and the System Security Objective.

…

~~**FCESS** (short for **Frequency Control Essential System Service**): Is defined in rule 201.~~

~~(In other regimes, FCESS is known as "regulation service")~~

~~**FCESS Payer**: Is defined in rule 227(e).~~

~~**FCESS Payment Share**: Is defined in rule 227(g).~~

~~**FCESS Payment Threshold**: Is defined in rule 227(a).~~

~~**FCESS Provider**: Is defined in rule 201, and includes a Primary FCESS Provider and a Secondary FCESS Provider.~~

…

Primary ~~FCESS~~ Regulation: Is defined in rule 203 ~~(1)~~.

~~**Primary FCESS Contract**: Means the contract the ISO must procure under rule 203.~~

Primary ~~FCESS~~ Regulation Provider: Is defined in rule 203 ~~(1)~~.

…

Regulation: Is defined in rule 201.

Regulation Balancing Point Share: Is defined in rule 227(g).

Regulation Payment Share: Is defined in rule 227(h).

Regulation Payment Threshold: Is defined in rule 227(a).

Regulation Provider: Is defined in rule 201, and includes a Primary Regulation Provider and a Secondary Regulation Provider.

Regulation Lower ~~Reserve~~: Is defined in rule 201 (b) (ii).

Regulation Raise ~~Reserve~~: Is defined in rule 201 (b) (i).

~~**Regulation Reserve**: Means Regulation Raise Reserve and Regulation Lower Reserve.~~

~~**Regulation Service**: See FCESS.~~

…

Secondary ~~FCESS~~ Regulation: Means Regulation that can be Enabled when the available Primary Regulation is not sufficient in a Credible Island or the Power System as a whole ~~a Generation Facility within a Credible Island capable of providing FCESS~~, as identified by the ISO under rule 205(2).

Secondary ~~FCESS~~ Regulation Provider: Is defined in rule 205(4).

…

~~**SRESS**: Is defined in rule 213.~~

~~**SRESS Contract**: Means the contract the ISO enters under rule 214(1).~~

…

…

Chapter 6 – Generation adequacy

…

155 Generator may give Allocation Notice

…

(3) For the purposes of rule 155(2)(b), any commitments under an ESS Contract to provide ~~SRESS~~ Contingency Reserve Raise or ~~FCESS~~ Regulation~~, or to Maintain frequency raise reserve,~~ count as an allocation to an end user.

{Example — A gentailer (**"MargeCo"**) has a 100 MW plant. It has contracted to provide 20 MW of ~~frequency raise reserve~~ Regulation Raise and 10 MW of ~~SRESS~~ Contingency Reserve Raise. MargeCo may allocate 70 MW under this rule 155, because those Essential System Service commitments are counted.}

…

Chapter 7 – System operations

Subchapter 7.1 – Key concepts

…

165 Definition of Normal Operating Conditions

A Power System is under **"Normal Operating Conditions"** when —

…

(e) the Primary ~~FCESS~~ Regulation Provider is providing ~~the~~ Primary ~~FCESS~~ Regulation ~~service~~ in accordance with its ~~the Primary FC~~ESS Contract; and

(f) each contracted ~~SRESS~~ CRR Provider is maintaining the amount of Headroom required by its ~~SR~~ESS Contract; and

…

…

Subchapter 7.5 – Operating the Power System

…

185 Responsibilities and powers in Normal Operating Conditions

…

(2) {**ISO Control Desk**} During Normal Operating Conditions the ISO Control Desk must —

…

(g) determine whether and when to Enable or Disable ~~FCESS~~ Regulation Providers under rule 215; and

…

Chapter 8 – Essential system services, balancing and settlement

{Outline — This Chapter 8 deals with the following —

- Subchapter 8.1 provides for the two Essential System Services to be procured by the ISO, being ~~FCESS (frequency control Essential System Service)~~ Regulation and ~~SRESS (spinning reserve Essential System Service)~~ Contingency Reserve Raise;
- Subchapter 8.2 deals with the energy balancing part of the EBAS (energy balancing and settlement) regime; and
- Subchapter 8.3 deals with the settlement part of the EBAS regime, in which contract notes are issued to settle payments for both Essential System Services and Imbalances.
- Subchapter 8.4 contains miscellaneous EBAS provisions.}

Subchapter 8.1 – Essential system services

{Outline — This Subchapter 8.1 deals with the specification, procurement and Enablement of —

- ~~FCESS (frequency control Essential System Service, also known as "regulation" service)~~Regulation to regulate frequency in the Power System and any Islands; and
- ~~SRESS (spinning reserve Essential System Service, also known as "contingency reserve")~~Contingency Reserve Raise to ensure there is adequate Headroom in the Power System and any Islands.

Following a Contingency, the required ~~Spinning Reserve~~ Contingency Reserve Raise capacity will come from the ~~FCESS~~ Regulation Provider, and, once frequency falls outside the droop frequency deadband, from the droop response of all Enabled Generating Units including the ~~SRESS~~ CRR Provider's units, using the Headroom available in each unit.

ESS Providers will be paid a price determined under this Subchapter 8.1 for making available the Essential System Service capacity. If a Generating Unit then provides or absorbs energy in the course of providing an Essential System Service, and the energy is not otherwise traded under private contractual arrangements, then the energy will be is balanced through the energy balancing regime in Subchapter 8.2 and settled under Subchapter 8.3.}

…

201 Definition – Frequency ~~control service (a.k.a.~~ Regulation ~~Service)~~

~~The frequency control service (**"FCESS"**)~~Regulation is ~~a service~~ an Essential System Service in which a person (the **"~~FCESS~~ Regulation Provider"**) —

(a) frequently and rapidly raises or lowers the output of one or more Generating Units in order to keep the Power System's frequency within the Frequency Tolerance Band; and

(b) ensures that it operates its online Generating Units in such a way that —

(i) it has a reserve of generation capacity online (**"Regulation Raise ~~Reserve~~"**) in order to be able to provide the "raise" referred to in rule 201(a); and

(ii) its Generators are sufficiently loaded (**"Regulation Lower ~~Reserve~~"**), to be able to provide the "lower" referred to in rule 201(a),

which together comprise **"Regulation ~~Reserve~~"**.

202 Requirements – ~~Frequency control~~ Regulation – ISO to determine

The ISO must, having regard to the objectives in rule 199, from time to time determine the appropriate amounts of Regulation Raise ~~Reserve~~ and Regulation Lower ~~Reserve~~ to be —

(a) contracted for with the Primary ~~FCESS~~ Regulation Provider under rule 203, and the required availability for that Regulation ~~Reserve~~; and

(b) made available by a Secondary ~~FCESS~~ Regulation Provider when it is Enabled under rule 209.

203 Procurement – Primary ~~FCESS service~~ Regulation

The ISO must from time to time procure an ESS Contract with a **"Primary ~~FCESS~~ Regulation Provider"**, whose task will be to —

(a) Maintain frequency within the Frequency Tolerance Band for the Power System as a whole (or, if an Islanding Event has occurred, for the Island in which the Primary ~~FCESS~~ Regulation Provider is located); and

(b) Maintain levels of Regulation Raise ~~Reserve~~ and Regulation Lower ~~Reserve~~ at least equal to the amounts, and with at least the availability, determined by the ISO under rule 202(a).

204 Pricing – Primary ~~FCESS service~~ Regulation

(1) The price and other terms of the ~~Primary FC~~ESS Contract for Primary Regulation are to be negotiated in the ISO's discretion, having regard to the objectives in rule 199.

(2) The ~~Primary FC~~ESS Contract for Primary Regulation will set out the ~~FCESS~~ Primary Regulation Provider's entitlement to be paid under rule 228(1)(c).

{Rule 204(2) places the payment in the contract. In contrast, for Secondary ~~FCESS~~ Regulation Providers the entitlement to be paid appears directly in rule 209(4).}

205 Identifying Islanding scenarios and Secondary ~~FCESS~~ Regulation Providers

(1) The ISO must identify all Credible Islanding scenarios for the Power System.

(2) The ISO must identify and select as many generation facilities as necessary, to ensure that there is within each Credible Island at least one Generation Facility capable of providing ~~FCESS~~ Regulation.

{These generation facilities will also be able to provide ~~FCESS~~ Regulation to the Power System as a whole, if the Primary ~~FCESS~~ Regulation Provider is not doing so.}

(3) Wherever practicable, having regard to the objectives in rule 199, under rule 205(2) the ISO is to select only generation facilities in Covered Networks, unless a Generator in a Non-Covered Network agrees otherwise.

(4) The Generator who controls a Generation Facility selected under rule 205(2) is a potential **"Secondary ~~FCESS~~ Regulation Provider"**.

(5) The ISO must notify each potential Secondary ~~FCESS~~ Regulation Provider —

(a) that its Facility has been selected by the ISO under rule 205(2); and

(b) of the amounts of Regulation Raise ~~Reserve~~ and Regulation Lower ~~Reserve~~ it will be required to make available if it is Enabled under rule 209, as determined by the ISO under rule 202(b).

206 Pricing – Secondary ~~FCESS service~~ Regulation

(1) A potential Secondary ~~FCESS~~ Regulation Provider must, within 2 months after being notified under rule 205(5), notify the ISO of its proposed price (in dollars per hour) for providing Secondary ~~FCESS~~ Regulation, and may thereafter (but no more than once in any 12-month period) notify the ISO of changes to the price.

(2) A price proposed under rule 206(1) —

(a) must be set at a level which fairly compensates the Secondary ~~FCESS~~ Regulation Provider for the actual Direct and indirect marginal cost of providing Secondary ~~FCESS~~ Regulation, including fuel consumption, heat rate impacts and additional maintenance; but

(b) must not include any fixed costs such as plant capital cost or corporate overheads, a return on capital or other profit margin.

(3) The ISO may from time to time determine and Publish an **"Administered Secondary ~~FCESS~~ Regulation Price"** (in dollars per hour) which is the ISO's reasonable estimate of a price consistent with rule 206(2).

(4) The Administered Secondary ~~FCESS~~ Regulation Price applies as a cap on a price proposed under rule 206(1).

(5) The ISO must use the prices proposed by each potential Secondary ~~FCESS~~ Regulation Provider under rule 206(1) (as capped, if applicable, under rule 206(4)), to develop and Maintain a cost-based Enablement order of merit for Secondary ~~FCESS~~ Regulation Providers.

207 Enablement – ~~Frequency control~~ Regulation – One provider at a time

(1) No more than one ~~FCESS~~ Regulation Provider should be Enabled in an Island, or in a non-Islanded Power System.

(2) A Protocol or other Procedure may set out an exception to rule 207(1).

208 Enablement – Primary ~~frequency control~~ Regulation

(1) The Primary ~~FCESS~~ Regulation Provider should be Enabled at all times, unless a Protocol requires otherwise, or the ISO Control Desk directs otherwise under Subchapter 7.5 or the ESS Contract.

(2) While Enabled, the Primary ~~FCESS~~ Regulation Provider must ensure it maintains frequency as described in rule ~~203(1)(a)~~ 203(a), and makes available Regulation Raise ~~Reserve~~ and Regulation Lower ~~Reserve~~ at least to the levels determined under rule 202(a) as described in rule ~~203(1)(b)~~ 203(b).

209 Enablement – Secondary ~~frequency control~~ Regulation

(1) If for any reason the Primary ~~FCESS~~ Regulation Provider is not maintaining frequency in an Island (or the Power System as a whole), then the ISO Control Desk must, for each such Island (or the Power System) —

(a) identify all potential Secondary ~~FCESS~~ Regulation Providers available to the Island (or Power System); and

(b) use the cost-based Enablement order of merit developed under rule 206(5) to select the lowest-cost available Secondary ~~FCESS~~ Regulation Provider for the Island (or Power System);

(c) Promptly by voice or other means Direct the selected Secondary ~~FCESS~~ Regulation Provider to start providing ~~FCESS~~ Regulation (**"Enable"**); and

(d) when appropriate, in coordination with the affected Registered NSPs, by voice or other means Direct the Secondary ~~FCESS~~ Regulation Provider to stop providing ~~FCESS~~ Regulation (**"Disable"**).

(2) The ISO must, so far as practicable consistent with its other obligations under these Rules, endeavour to minimise the occasions on which, and duration for which, a Secondary ~~FCESS~~ Regulation Provider is Enabled.

(3) A Secondary ~~FCESS~~ Regulation Provider must, from the time it is Enabled under rule 209(1)(c) until the time it is Disabled under rule 209(1)(d) —

(a) provide ~~FCESS~~ Regulation; and

(b) ensure it keeps available the amounts of Regulation Raise ~~Reserve~~ and Regulation Lower ~~Reserve~~ notified to it under rule 205(5)(b).

(4) A Secondary ~~FCESS~~ Regulation Provider is entitled to be paid (in dollars per hour) under rule 228(2)(b) for providing ~~FCESS~~ Regulation, at the lower of the price it most recently proposed under rule 206(1), or the Administered Secondary ~~FCESS~~ Regulation Price under rule 206(4) —

(a) from the time it starts providing ~~FCESS~~ Regulation; and

(b) until the time it is Disabled, or the time it stops providing ~~FCESS~~ Regulation, whichever is earlier.

210 ~~Spinning reserve~~ Contingency Reserve Raise – Definition of Headroom

In these Rules —

(a) **"Headroom"** at any time —

(i) for a Generating Unit — means the difference between its actual output at the time, and its maximum output capability at the time taking into account environmental conditions and Equipment Limits;

{For each Generating Unit, Headroom measures its droop response capacity to help arrest a fall in frequency after a Contingency.}

and

(ii) for the Power System — means the aggregate, across all Enabled Generating Units in the Power System at any time of each Generating Unit's Headroom as defined in 210(a)(i) at the time; and

(b) **"Required Headroom"** means the amount of Headroom needed in the Power System (or, if applicable, a Credible Island) to satisfy the Contingency Reserve Raise Standard, determined by the ISO or ISO Control Desk under rule 212(1); and

(c) **"Required Headroom Level"** for the Power System or an Island is determined by the ISO under rule 212(1)(a) or by the ISO Control Desk under rule 212(2)(a).

211 Requirements – ~~Spinning reserve~~ Contingency Reserve Raise – The Contingency Reserve Raise Standard

The **"Contingency Reserve Raise Standard"** is that the quantity of Headroom within the Power System (or, if applicable, a Credible Island) at any time must be sufficient to Enable the Power System (or Credible Island) to remain within the Frequency Operating Standards following the largest single Credible Contingency which could cause a shortfall between generation and Load on a Covered Network.

212 Requirements – ~~Spinning reserve~~ Contingency Reserve Raise – ISO to determine

(1) The ISO must either —

(a) from time to time determine and Publish the Required Headroom Level for the Power System (or, if the ISO determines it to be appropriate, a Credible Island); or

(b) if it determines that a more flexible approach will better serve the objective in rule 199(2) — from time to time determine and Publish the process and Decision criteria which the ISO Control Desk is to apply to determine the Power System's (or, if the ISO determines it to be appropriate, a Credible Island's) Required Headroom Level from time to time, depending on the Power System's configuration and other circumstances.

(2) If the ISO has published Decision criteria under rule 212(1)(b), the ISO Control Desk must —

(a) as frequently as required by the criteria, apply the criteria to determine the Required Headroom Level; and

(b) notify each ~~SRESS~~ CRR Provider of the Required Headroom Level whenever it changes.

213 Definition – ~~The spinning reserve (~~Contingency ~~r~~Reserve Raise~~) service~~

~~The spinning reserve service (~~**~~"SRESS")~~** ~~is a service~~ Contingency Reserve Raise (**"CRR"**) is an Essential System Service in which a person (the **"~~SRESS~~ CRR Provider"**) commits to Maintain an amount of Headroom in its Generating Units which equals or exceeds a specified amount, at a specified level of availability.

214 Procurement – ~~Spinning reserve~~ Contingency Reserve Raise contracts

(1) The ISO must from time to time enter into an ESS Contract with one or more ~~SRESS~~ CRR Providers to obtain ~~SRESS~~Contingency Reserve Raise.

(2) The ISO must ensure that the aggregate amount of ~~SRESS~~ Contingency Reserve Raise for which it contracts is sufficient to ensure that —

(a) in Normal Operating Conditions, the ~~SRESS~~ CRR Provider or CRR P~~p~~roviders between them Maintain an amount of Headroom which meets or exceeds the Required Headroom Level with a level of availability which is acceptable to a GEIP standard; and

(b) outside Normal Operating Conditions, or otherwise where necessary for example due to Network constraints, the ISO Control Desk can Enable a Generating Unit to provide ~~SRESS~~ Contingency Reserve Raise in order to ensure that there is an amount of Headroom available to each part of the Power System, which meets or exceeds the Required Headroom Level.

(3) The Regulation Raise ~~Reserve~~ specified, or to be specified, in the ~~Primary FCESS Provider's ESS Contract~~ ESS Contract for Primary Regulation may be counted as contracted ~~SRESS~~ Contingency Reserve Raise for the purposes of rule 214(2).

(4) If the ISO contracts with more than one ~~SRESS~~ CRR Provider, the contracts may specify how the obligation to Maintain Headroom in rule 214(2)(a) is to be apportioned and managed between the ~~SRESS~~ CRR Providers.

(5) The price and other terms of an ~~SR~~ESS Contract for Contingency Reserve Raise are to be negotiated in the ISO's discretion, having regard to the objectives in rule 199.

(6) The ~~SR~~ESS Contract will set out the ~~SRESS~~ CRR Provider's entitlement to be paid under rule ~~228(2)(b)~~ 230(c).

215 Enablement – ~~Spinning reserve~~ Contingency Reserve Raise

The ISO Control Desk must on a 24/7 Basis —

(a) monitor the Power System; and

(b) outside Normal Operating Conditions, or otherwise where necessary for example due to Network constraints — Enable Generating Units to provide ~~SRESS~~ Contingency Reserve Raise as necessary,

to ensure that the Headroom available in each part of the Power System, having regard to Network configuration and constraints, meets or exceeds the Required Headroom Level.

216 ~~Spinning reserve~~ Contingency Reserve Raise – Trial of alternative ~~SRESS~~ approach

If the ISO considers that the objectives in rule 199 might be better served by an alternative ~~SRESS~~ Contingency Reserve Raise approach, then it may, in consultation with Rules Participants —

(a) propose and develop trials of an alternative ~~SRESS~~ Contingency Reserve Raise approach; and

(b) determine whether there is support for an alternative approach, and whether the approach can adequately achieve the primary objective in rule 199(1) in a way which maximises the secondary objective in rule 199(2); and

(c) thereafter develop and submit suitable Rule Change Proposals or Procedure Change Proposals to implement the alternative approach.

{Example — In a "dynamic Enablement" approach, the ISO Control Desk, on a 24/7 Basis or otherwise, monitors and takes into account the aggregate Headroom available across all (or selected) Generating Units in the Power System (also known as "incidental Headroom"), and Enables and Disables Generating Units as necessary to minimise machine starts while ensuring that the aggregate available Headroom does not fall below a specified margin.}

…

Subchapter 8.3 – Settlement

226 Reference period for ~~FCESS~~ Regulation and ~~SRESS~~ Contingency Reserve Raise settlement

The **"Reference Period"** for a Settlement Period is the 3 full Financial Years preceding the Financial Year in which the Settlement Period occurs.

{Example — For each Settlement Period in the 2020/21 Financial Year, the Reference Period covers the three Financial Years 2017/18, 2018/19 and 2019/20.}

227 ~~Frequency control~~ Regulation – Identify Payers and their shares

The Payers for ~~FCESS~~ Regulation in a Settlement Period, and their proportionate ~~FCESS~~ Regulation Payment Shares, are determined as follows —

(a) The **"~~FCESS~~ Regulation Payment Threshold"** is a Load Swing of 5 MWh.

(b) **Step 1 — identify** all Balancing Points with at least one negative Metered Quantity for a Trading Interval in the Reference Period — these are the **"Exit Balancing Points"**.

(c) **Step 2 —** for each Exit Balancing Point, compile the set comprising all negative metered quantities for Trading Intervals in the Reference Period.

(d) **Step 3 —** Using the set compiled in Step 2, calculate the following for each Exit Balancing Point, with all values expressed in in MWh —

"Average Load"	=	the simple average of Metered Quantities across the set
"Maximum Load"	=	the Metered Quantity in the set with the highest absolute value
"Minimum Load"	=	the Metered Quantity in the set with the lowest absolute value
"Positive Load Swing"	=	the absolute value of the Maximum Load minus the absolute value of the Average Load
"Negative Load Swing"	=	the absolute value of the Average Load minus the absolute value of the Minimum Load
"Load Swing"	=	the Positive Load Swing plus the Negative Load Swing.

(e) **Step 4 — identify** all Exit Balancing Points (**"Relevant Balancing Points"**) at which the Load Swing was bigger than the ~~FCESS~~ Regulation Payment Threshold.

(f) **Step 5 — identify** each **"Payer"** for ~~FCESS~~ Regulation in the Settlement Period, being the Nominator associated with each relevant Balancing Point.

(g) **Step 6 —** for each relevant Balancing Point, determine the associated Payer's **"~~FCESS~~ Regulation Balancing Point Share"** for the Settlement Period as follows —

$$\text{~~FCESS~~Regulation balancing point share}_b = \frac{\text{Relevant Load Swing}_b}{\sum \text{Relevant Load Swings}}$$

where —

$\text{~~FCESS~~Regulation balancing point share}_b$	=	the proportional ~~FCESS~~ Regulation Balancing Point Share for the Payer at relevant Balancing Point b
$\text{Relevant Load Swing}_b$	=	the Load Swing for the relevant Balancing Point b
$\text{Relevant Load Swings}$	=	the sum of all Load Swings for the Reference Period across all Relevant Balancing Points.

(h) **Step 7 —** for each Payer, determine the Payer's aggregate **"~~FCESS~~ Regulation Payment Share"** for the Settlement Period as follows —

$$\text{~~FCESS~~Regulation balancing point share}_p = \sum \text{~~FCESS~~Regulation balancing point shares}_{bp}$$

$\text{~~FCESS~~Regulation balancing point share}_p$	=	the aggregate payment share for ~~FCESS~~ Regulation for Payer ***p***
$\text{~~FCESS~~Regulation balancing point shares}_{bp}$	=	the ~~FCESS~~ Regulation Balancing Point Share determined under Step 6 at each relevant Balancing Point ***b*** for which Payer ***p*** is the Payer.

228 ~~Frequency control~~ Regulation — Payment obligations

(1) For Primary ~~FCESS~~ Regulation, for a Settlement Period —

(a) the **"Payee"** is the Primary ~~FCESS~~ Regulation Provider (unless it was not Enabled to provide ~~FCESS~~ Regulation at all, during the Settlement Period); and

(b) a **"Payer"** is each Nominator identified Step 5 in rule 227;

{This rule places the immediate ~~FCESS~~ Regulation payment obligation on the Nominator, who by default (under the combined effects of rules 220(4) and 223) will be the Network User under rule. However, as with ~~SRESS~~ Contingency Reserve Raise, the Nominator can allocate the obligation to another person under rule 238.}

and

(c) the total amount to be paid to the Payee is determined under its ~~Primary FCESS~~ ESS Contract in accordance with rule 204(2); and

(d) the proportionate share of this amount to be paid by each Payer is its ~~FCESS~~ Regulation Payment Share calculated at Step 7 in rule 227.

(2) For each occasion in a Settlement Period on which Secondary ~~FCESS~~ Regulation was Enabled in an Island or the Power System —

(a) the **"Payee"** is the Secondary ~~FCESS~~ Regulation Provider; and

(b) the total amount to be paid to the Payee is determined under rule 209(4); and

(c) the **"Payers"** and their proportionate shares are the same as in rule 228(1).

229 ~~Spinning reserve~~ Contingency Reserve Raise – Identify Payers and their shares

(1) The Payers for ~~SRESS~~ Contingency Reserve Raise in a Settlement Period, and their proportionate ~~SRESS~~ CRR Payment Shares, are determined as follows —

(a) The **"~~SRESS~~ CRR Payment Threshold"** ($\mathbf{MW}_0$) equals the Regulation Raise ~~Reserve~~ specified in the Primary ~~FCESS~~ Regulation Provider's ESS Contract,

in MW (and if this value changes during a Settlement Period, the smaller value is to be used for the full Settlement Period).

(b) **Step 1 — identify** —

(i) all Balancing Points at which at least one Generating Unit was Connected (directly or indirectly) to the Power System during the Reference Period (**"Entry Balancing Points"**); and

(ii) the Nominator associated under rule 220 with each Entry Balancing Point.

(c) **Step 2 —** for each Nominator identified in Step 1, identify all Generating Units Connected (directly or indirectly) during the Reference Period at all Balancing Points with which it is associated, and identify the one with the largest operational capacity which is capable of forming a Contingency Outage in MW — this is the Nominator's **"Reference Unit"**.

(d) **Step 3 —** identify the **"Payers"** for ~~SRESS~~ Contingency Reserve Raise in the Settlement Period, being the Nominators identified in Step 1 which have Reference Units bigger than the ~~SRESS~~ CRR Payment Threshold.

(e) **Step 4 —** rank the Payers by reference to the size of their Reference Units, from smallest ($rank_p$ = 1) to largest ($rank_p$ = ***n***).

(f) **Step 5 —** for each ~~SRESS~~ Contingency Reserve Raise Payer ***p***, perform the following calculation to determine its proportionate **"~~SRESS~~ CRR Payment Share"** for the Settlement Period —

$$\sum_{i=1}^{rank_p} \frac{MW_i - MW_{(i-1)}}{[MW_n - MW_0] \times (n + 1 - i)}$$

where —

$SRESSCRR\ share_p$	=	the proportional ~~SRESS~~ CRR Payment Share for Payer ***p***
i	=	the summation index number
$rank_p$	=	the rank assigned to Payer ***p*** in Step 4 (rule 229(1)(e))
n	=	the number of Payers identified in Step 3 (rule 229(1)(d))
MW_i	=	the nameplate capacity in MW of the Reference Unit for each Payer $_i$ (such that MW_p is the nameplate capacity for Payer ***p***), determined under Step 2 (rule 229(1)(c))
MW_0	=	the ~~SRESS~~ CRR Payment Threshold determined under rule 229(1)(a).

{The calculation in Step 5 is known as the "runway model". It allocates the greatest share to the Payer with the largest Reference Unit. The proportionate shares it calculates sum to 1.}

230 ~~Spinning reserve~~ Contingency Reserve Raise – Payment obligations

For ~~SRESS~~ Contingency Reserve Raise, for a Settlement Period —

(a) a **"Payee"** is each ~~SRESS~~ CRR Provider contracted to provide ~~SRESS~~ Contingency Reserve Raise at any time in the Settlement Period; and

(b) a **"Payer"** is each Nominator identified in Step 3 in rule 229(1);

{This rule places the immediate ~~SRESS~~ Contingency Reserve Raise payment obligation on the Nominator, who by default (under the combined effects of rules 220(4) and 223) will be the Network User. However, as with ~~FCESS~~ Regulation, the Nominator can allocate the obligation to another person under rule 238.}

and

(c) the total amount to be paid to the Payee is determined under rule 214(5); and

(d) the proportionate share of this amount to be paid by each Payer is calculated at Step 5 in rule 229(1).

…

232 Balancing – Not all Positive Imbalances to be compensated

Except as specified in this Subchapter 8.3, there is to be no payment for Positive Imbalances.

{For Positive Imbalances, this Subchapter 8.3 provides for payment to only ~~FCESS~~ Regulation Providers, persons complying with a System Operations Direction, and when the Power System was in a Non-normal EBAS State — see rules 235(2)(b), 235(2)(c) and 235(2)(d) respectively.}

…

234 Balancing – Payment obligations – Definitions

(1) For the purposes of rule 235 the Power System is in a **"Normal EBAS State"** for a Trading Interval if, for the whole of the Trading Interval —

(a) frequency is within the Normal Frequency Tolerance Band and being maintained there by the Primary ~~FCESS~~ Regulation Provider; and

(b) no Islands have formed; and

(c) the Primary ~~FCESS~~ Regulation Provider, in providing the Regulation ~~Service~~ it contracted under rule 203(1)(a) to provide, was not required to use more than the levels of Regulation ~~Reserve~~ it contracted under rule 203(1)(b) to Maintain.

…

235 Balancing – Payment obligations

(1) This rule 235 applies to determine payment amounts for energy balancing, for each Trading Interval in a Settlement Period.

(2) Each Balancing Nominee with a Positive Imbalance is a **"Payee"**, entitled to be paid a price per MWh for its Positive Imbalance determined as follows —

(a) generally, that is unless one of rules 235(2)(b) to 235(2)(d) applies — the Payee is to be paid —

PIQ x **AP**, for MWh up to PBTQ; and

zero, for MWh above PBTQ;

and

(b) if the Payee is a~~n FCESS~~ Regulation Provider — it is to be paid —

PIQ x **AP**;

and

…

(3) Each Balancing Nominee with a Negative Imbalance is a **"Payer"**, required to pay a price per MWh for its Negative Imbalance determined as follows —

(a) generally, that is unless one of rules 235(3)(b) to 235(3)(d) applies — the Payer is to pay —

|NIQ| x **AP**, for MWh up to **|NBTQ|**; and

|NIQ| x **APP**, for MWh above **|NBTQ|**;

and

(b) if the Payer is a~~n FCESS~~ Regulation Provider — unless rule 235(3)(d) applies, it is to pay —

|NIQ| x **AP**, for MWh up to **|NBTQ|**; and

zero, for MWh above **|NBTQ|**;

and

…

Appendix 4 – Transitional Rules

…

Sub-appendix 4.5 – Energy balancing and settlement (including ESS payment)

…

Energy balancing and settlement

A4.33 After it issues the EBAS Readiness Notice, the ISO is to determine Imbalance quantities in accordance with Subchapter 8.2.

A4.34 The ISO may in its absolute discretion Delegate the performance of its function under rule A4.33 to any person. Subchapter 2.2 does not apply in respect of the Delegation.

A4.35 For a Legacy User from 1 July 2021 to 6 January 2022 —

(a) payments to and by the Legacy User in respect of energy Imbalances (including Imbalances determined under rule A4.33) and Essential System Services are to be determined and made in accordance with its existing contract; and

(b) a payment note which purports to name the Legacy User as a Payer or Payee is of no effect.

A4.36 For a New User from 1 July 2021, and for a Legacy User from 7 January 2022, balancing and settlement matters, including payments to and by the New User in respect of energy Imbalances and Essential System Services, are to be resolved and administered in accordance with the rules in Chapter 8, modified as follows —

{This rule A4.36 is only a transitional rule. From 1 July 2023 at the latest, energy balancing and settlement for both New Contracts and existing contracts will be dealt with under Chapter 8.}

(a) although balancing and settlement are to apply from 1 July 2021 and 7 January 2022, for New Users and Legacy Users respectively, the ISO is to defer undertaking the actual settlement calculations for each Settlement Period until at least 15 Business Days after it has issued the EBAS Readiness Notice, at which point it is to undertake the calculations for each Settlement Period in arrears; and

(b) the Administered Price is to be determined and published by the ISO from time to time, for which purpose the ISO may inform itself as it sees fit; and

(c) subject to rule A4.41(a), no payments are to be made in respect of Secondary ~~FCESS~~ Regulation; and

(d) the Administered Penalty Price is to be 130% of the Administered Price; and

(e) in each payment note issued to the New User or Legacy User —

(i) if during the settlement interval Horizon Power paid for Primary ~~FCESS~~ Regulation under rules A4.38 or A4.39 — Horizon Power is to be inserted as Payee in place of the Primary ~~FCESS~~ Regulation Provider; and

(ii) if during the settlement interval Horizon Power paid for primary ~~SRESS~~ Contingency Reserve Raise under rules A4.42 or A4.43 — Horizon Power is to be inserted as Payee in place of the primary ~~SRESS~~ CRR Provider; and

(iiA) if during the settlement interval Horizon Power paid (or was paid) for balancing electricity under rules A4.38 or A4.39 — Horizon Power is to be inserted as Payee (or Payer, respectively), in place of the Payee (or Payer) identified by the ISO under these Rules; and

(iii) otherwise — the Covered NSP who is the counterparty to the New User's New Contract is to be substituted as the counterparty Payee or Payer;

and

(f) in place of rule 237(1)(b), any Surplus is to be retained by the relevant Covered NSP.

…

Sub-appendix 4.6 – Essential system services

…

Transition for frequency control (regulation) and balancing

A4.38 While the Prior Arrangement between Rio Tinto and Horizon Power is in effect, Rio Tinto will provide, and be paid for, the Primary ~~FCESS~~ Regulation service in accordance with the Prior Arrangement, and the parties will pay, and be paid for, electricity imbalances in accordance with the Prior Arrangement.

A4.39 If the Prior Arrangement between Rio Tinto and Horizon Power will no longer be in effect, then Horizon Power must enter into a New Arrangement in accordance with rules A4.48 to A4.52 to replace it.

A4.40 If a Secondary ~~FCESS~~ Regulation service is required, whether due to an Islanding Event or otherwise, then —

(a) Horizon Power is to provide or procure it; and

(b) if Horizon Power is not providing, and has not procured, Secondary ~~FCESS~~ Regulation service in an Island under rule A4.40(a), then Alinta DEWAP is to provide or procure it in accordance with its existing contract.

{The current contractual arrangement, in which one of Alinta's machines will enter Isoch mode when a control set point is reached, after which Horizon Power will take over Secondary ~~FCESS~~ Regulation and Alinta will revert to droop mode, will continue in accordance with the contract.}

A4.41 If Horizon Power or Alinta DEWAP provides Secondary ~~FCESS~~ Regulation service, then —

(a) if and for so long as they are the only Rules Participant providing ~~FCESS~~ Regulation service in the NWIS — they are to be paid the same amount as Rio Tinto would have been under its Prior Arrangement; but

(b) otherwise — they are not to be paid.

…

Schedule 2: Placeholder – suspension of planning

Explanatory Note

Rule 279 requires the ISO to develop Network Coordination and Planning Reports (NCP Reports) every two years with the first NCP Reports to be published on 1 July 2027. However, industry feedback indicates that there is little need for these at this time. Further feedback will be sought on what the most useful content to include in long-term planning reports is, and on the frequency of reporting. Once this is determined, further Amending Rules will be developed to implement the improved reporting requirements.

…

8 Glossary

…

~~**NCP Planning Horizon**: Is defined in rule 280(1).~~

~~**NCP Reports**: Means the Network coordination and planning reports to be published under rule 279.~~

~~{Under rule 279, the NCP Reports comprise a Transmission Development Plan under rule 281 and a Pilbara GenSOO under rule 282.}~~

~~**NCP Reports Publication Date**: Is defined in rule 233(1).~~

…

~~**Pilbara GenSOO** {short for "Pilbara Generation Statement of Opportunities"}: Means a generation statement of opportunity for the Pilbara under rule 282.~~

…

~~**Transmission Development Plan**: Means the plan the content of which is set out in rule 281.~~

…

Subchapter 10.1 – Long term coordination and planning

…

277 Network coordination and planning objectives

(1) Subject to rule 276, the primary objective of this Subchapter 10.1 is to produce reports which —

(a) provide Credible, independent information over substantial forecast periods for potential developers of electricity networks, Generating Works and loads in the Pilbara, with the aim of —

(i) promoting efficient use of and investment in; and

(ii) facilitating efficient and coordinated development of,

existing, new and augmented Pilbara networks; and

(b) to facilitate access under the Access Code to the services of Covered Networks.

(2) The secondary objective of this Subchapter 10.1 is to pursue the primary objective in a manner which —

(a) so far as reasonably practicable, minimises cost and disruption to Rules Participants; and

(b) in Connection with an Integrated Mining Network — has regard to rule 5, but only until evolution occurs as contemplated by rule 276.

…

279 Coordinator to develop a framework for long-term planning reports

The Coordinator, in consultation with the ISO, is to develop and publish a framework for long-term planning reports that will meet the objectives in rule 277.

280 ISO may publish network planning information

The ISO may prepare and publish information, reports, studies, forecasts or assessments related to the current and future capability, operation, development, security, reliability or limitations of the NWIS, if the ISO considers that such publication would assist with:

(a) network planning;

(b) access and connection to the NWIS;

(c) the efficient development and operation of the NWIS;

(d) the achievement of the ISO's functions, objectives or obligations under these Rules or the Act; or

(e) the achievement of the Pilbara Electricity Objective.

…

~~**279 ISO to prepare and Publish biennial NCP Reports**~~

~~(1) The ISO must prepare and Publish, in accordance with this Subchapter 10.1 and the Planning and Reporting Procedure, the following Network coordination and planning reports ("NCP Reports") —~~

~~(a) a Transmission Development Plan under rule 281; and~~

~~(b) a Pilbara GenSOO under rule 282.~~

~~(2) The NCP Reports must be published every two years by 1 July and the first NCP Reports are to be published by 1 July 2027.~~

280 NCP Planning Horizon

The NCP Reports are to cover a period specified in the Planning and Reporting Procedure (**"NCP Planning Horizon"**).

281 Transmission Development Plan – NWIS

A Transmission Development Plan is to set out, across the NCP Planning Horizon —

(a) a description of the NWIS's current Covered Transmission Elements; and

(b) a range of Credible scenarios for the locations and quantities of electricity supply and demand in NWIS Covered Networks (including locations which the NWIS is reasonably capable of servicing if it is suitably augmented); and

(c) for each Covered Network in the NWIS, a consolidated summary of the Covered NSP's most-recently-published proposed and contemplated Augmentations; and

(d) having regard to the supply and demand scenarios developed under rule 281(b) and Augmentation information published under rule 281(c) —

(i) current and projected areas of Network Constraint in the NWIS Covered Networks; and

(ii) possible efficient development strategies for extension or expansion of the NWIS Covered Networks including opportunities for co-optimisation of Network and non-Network investment, and opportunities for private investment; and

(iii) possible opportunities for new, extended or expanded Pilbara networks which may Interconnect with the NWIS;

and

(e) any other information required by the Planning and Reporting Procedure or which the ISO considers appropriate.

282 Pilbara GenSOO

A generation statement of opportunity for the Pilbara (**"Pilbara GenSOO"**) is to set out —

(a) possible efficient investment opportunities in new or expanded generation facilities and (if applicable) Storage Works for supply into the NWIS Covered Networks (including from locations which could supply into the NWIS if it is suitably augmented) over the NCP Planning Horizon; and

(b) the ISO's projections of Generator fuel availability, new fuel sources, and renewable and intermittent energy developments over the NCP Reports planning horizon; and

(c) a report on Essential System Services acquired by the ISO for the NWIS since the last NCP Reports Publication Date; and

(d) an assessment of the adequacy of system capacity in the NWIS Covered Networks over the NCP Planning Horizon, having regard to the Generation Adequacy Objective; and

(e) any other information required by the Planning and Reporting Procedure or which the ISO considers appropriate.

283 Reports to consider broader Pilbara to the extent practicable

(1) A Transmission Development Plan or a Pilbara GenSOO, or both, may —

(a) to the extent reasonably practicable weighing —

(i) the advantages contemplated by the objective in rule 276;

(ii) against —

(A) the disadvantages associated with gathering, analysing and reporting the information; and

(B) Subchapter 11.2;

and

(b) subject to rule 283(2); and

(c) in accordance with the Planning and Reporting Procedure,

include information of the sort contemplated by rules 281 and 282 respectively, in respect of existing, or potential new, extended or expanded, Non-Covered Networks which do not form part of the NWIS.

(2) For the first 5 years after the Rules Commencement Date, for a Generation Facility which is Connected to a Non-Covered Network which does not form part of the NWIS —

(a) the ISO may require the Controller of the Generation Facility to give the ISO the following information for the purposes of this Chapter 10, namely for each Generating Unit in the power station —

(i) its manufacturer and model; and

(ii) its nameplate capacity in MW; and

(iii) its fuel type; and

(iv) the date it was first commissioned;

and

(b) the ISO cannot require the Controller to give it any other information for the purposes of this Chapter 10.

284 Consultation

The ISO must undertake the Standard Consultation Process in respect of a Transmission Development Plan and a Pilbara GenSOO, including seeking submissions on —

(a) the principal inputs that it proposes to use for the preparation or revision of the NCP Reports; and

(b) the principal risks and issues over the NCP Planning Horizon relevant to the matters to be considered under rules 281 and 282.

285 ISO may inform itself as it sees fit

In preparing the NCP Reports, subject to the Planning and Reporting Procedure, the ISO may inform itself in any manner it sees fit.

286 Review of this Subchapter 10.1's scope and objective

(1) From time to time at least once every 5 years, the ISO must conduct a review of the processes and reports set out in this Subchapter 10.1 against the objective in rule 276 and the Pilbara Electricity Objective, and Publish a report on the subject.

(2) The review must include consultation with Registered NSPs and Public consultation following at least the Expedited Consultation Process.

(3) If the ISO recommends any changes to these Rules or a Procedure in the report, it must either submit a Rule Change Proposal or initiate a Procedure Change Process, as the case may be.

(4) Nothing in this rule 286 limits a person's right to submit a Rule Change Proposal or Procedure Change Proposal in respect of a matter relating to this Subchapter 10.1 at any time.

…

Schedule 3: Amending Rules regarding manual load shedding list

…

8 Glossary

…

Explanatory Note

Review outcome 11 of the EPNR Implementation Plan relates to manual load shedding and includes, under outcome 11.4, that the ISO will develop a manual load shedding priority list, identifying the order in which network elements and load will be disconnected in the case of a forecast energy shortfall.

Note that these proposed rule changes are only to provide for the development of the list; additional rule changes relating to the implementation of manual load shedding will be drafted at a later date.

Load Shedding: Means reducing or disconnecting Loads from a Power System.

…

Manual Load Shedding: Means Load Shedding that is directed by the ISO as a Pre-Contingent Action to maintain Power System Security and Reliability.

Manual Load Shedding Priority List: Means the list developed by the ISO under Rule 171(3).

…

Subchapter 7.3 – System coordination

…

178B ISO to develop Manual Load Shedding Priority List

(1) The ISO must compile, Maintain, and Publish a "**Manual Load Shedding Priority List**" that sets out the Loads, Facilities, Network Elements, and any other relevant Equipment to be prioritised, in whole or in part, in circumstances that require Manual Load Shedding.

(2) The format and content of the Manual Load Shedding Priority List are to be determined by the ISO in consultation with NSPs as appropriate.

(3) The ISO may inform itself as it sees fit in connection with this Rule 178B.

(4) NSPs must, subject to Subchapter 11.2, provide to the ISO any information requested by the ISO.

…

Schedule 4: Amending Rules regarding CPC Facilities

Explanatory Note

Review outcome 20 of the EPNR Implementation Plan relates to self-contained networks. As part of this it was determined that becoming a CPC Facility will not require the existence of non-compliant equipment. These rule changes remove that requirement.

Subchapter 9.3 – Compliance at Connection Point

{~~If the Subchapter 9.2 process identifies a Non-Compliant Component in the Equipment which a Connection Applicant seeks to Connect to the NWIS, then f~~For certain Connection Applicants (i.e. those with Eligible Equipment) this Subchapter 9.3 provides an alternative pathway to Connection, rather than resolving the matter under Subchapter 9.2 (e.g. under rule 270(5)(a)).}

274A Concept, definitions and eligibility

(1) {**Concept**} In this Subchapter 9.3, "**Connection Point Compliance**" means an arrangement in which Equipment which is assessed under Subchapter 9.2 ~~to include one or more Non-Compliant Components~~ is ~~nonetheless~~ permitted to Connect to the NWIS, because the Equipment's Controller or the Host NSP, or both, implement measures which have been agreed between the Controller, the ISO and the Host NSP to ensure that the Facility as a whole complies with these Rules at its Connection Point, ~~despite the non-compliance of the component~~.

(2) {**Definitions**} In these rules —

(a) "**CPC Facility**" means Eligible Equipment for which CPC Measures have been agreed under rule 274C and have been implemented; and

(b) "**CPC Measures**" for a CPC Facility means the measures which have been agreed for the facility between the Connection Applicant, the Host NSP and the ISO under rule 274C and recorded in writing under rule 274C(3)(a); and

(c) "**Eligible Equipment**" means a collection of Equipment which meets the requirements set out in rule 274A(3), as modified under rule 274A(4) if applicable; and

(d) "**Host NSP**" means the NSP of the NWIS Network to which the CPC Facility (or, if applicable, the Equipment which is proposed to become, or was previously, a CPC Facility) is, is to be, or was Connected.~~; and~~

~~(e) "Non-Compliant component" means Equipment or a component of Equipment which (whether due to its operation, characteristics, configuration, performance or capacity) does not comply with these Rules (including the Harmonised Technical Rules), and the non-compliance is not the subject of an exemption under these rules.~~

(3) {**Eligibility**} A collection of Equipment is eligible for Connection Point Compliance if together the pieces of Equipment —

(a) are electrically interconnected with each other; and

(b) are under the control of a single Controller; and

(c) do not include any Network component which is Covered; and

(d) [Blank]~~include at least one Non-Compliant Component; and~~

(e) subject to rule 274A(4), are connected to the NWIS by a Single Connection Point.

(4) {**Eligibility – multiple connection points**} If pieces of Equipment together —

(a) satisfy the requirements in rule 274A(3)(a) to (c~~d~~); but

(b) are connected to the NWIS by multiple Connection Points,

then the ISO in its absolute discretion may agree in accordance with the CPC Procedure to nonetheless classify the Equipment as a single set of Eligible Equipment, in which case (unless the CPC Procedure provides otherwise) the agreed CPC Measures must govern all the Connection Points, and this Subchapter 9.3 applies in respect of each of the Connection Points.

274B Application for Connection Point Compliance

(1) Subject to rule 274B(2), a Connection Applicant may apply for Connection Point Compliance by giving notice in writing to the Host NSP and the ISO in accordance with the CPC Procedure.

~~(2) A Connection Applicant cannot give a notice under rule 274B(1), unless —~~

~~(a) when the Connection Applicant's Access Application was processed under Subchapter 9.2, the Host NSP or the ISO —~~

~~(i) assessed for compliance with these rules (including the Harmonised Technical Rules) each component of the Equipment which the Access Application seeks to have Connected to the NWIS; and~~

~~(ii) identified within the Equipment one or more Non-Compliant Components;~~

~~and~~

~~(b) all of the Equipment which the Access Application seeks to have Connected to the NWIS is Eligible Equipment.~~

(2) A Connection Applicant cannot give a notice under Rule 274B(1), unless all of the Equipment which the Access Application seeks to have Connected to the NWIS is Eligible Equipment.

…

274C Assessing the application and agreeing CPC Measures

(1) If a Connection Applicant applies for Connection Point Compliance, then in accordance with the CPC Procedure —

(a) the Connection Applicant is to propose one or more CPC Measures to address ~~the~~ any non-compliance of Equipment behind the Connection Point; and

…

274E CPC Measures – Standard to be met

The Host NSP and the ISO must not agree to proposed CPC Measures unless satisfied to a GEIP standard that the measures, if implemented and maintained, are sufficient to ensure that —

(a) the CPC Facility —

(i) complies with these Rules (including the Harmonised Technical Rules) at the CPC Facility's Connection Point, ~~despite any non-compliance by a Non-Compliant Component~~; and

…

274F CPC measures – Effect

(1) While the CPC Facility's Controller and the CPC Facility (and the Host NSP, to the extent the CPC Measures place obligations on it) are complying with the CPC Measures and this Subchapter 9.3, but only for so long as the Facility remains compliant at the Connection Point, ~~a Non-Compliant Component's Non-Compliance with these Rules~~ any non-compliance of Equipment behind the Connection Point is to be disregarded.

…

Schedule 5: Amending Rules regarding access to Power System Model

Explanatory Note

The purpose of these proposed rule changes is to clarify that the ISO may provide a Reduced Power System Model to prospective new connections, as appropriate and in a form that complies with existing confidentiality requirements.

…

8 Glossary

…

Network Model: Means the software model a Registered NSP is required by rule 110(1) to develop for its Network, or the software model a Prospective Registered NSP is required by rule 110B(1) to provide to the ISO for a relevant Network.

…

Prospective Registered NSP: Means a person who is considering becoming the NSP of a Registered NWIS Network, including but not limited to the NSP of a Non-NWIS Network that is considering connecting the Network to the NWIS, and has submitted a successful application to the ISO under rule 114B(1) to obtain access to the Reduced Power System Model.

…

Reduced Network Model: Means a version of an NSP's Network Model that has been modified to remove or protect confidential information in accordance with rule 116A.

…

Reduced Power System Model: Means a version of the Power System Model developed and Maintained by the ISO that has had Confidential Information removed or protected for the purpose of providing it to Rules Participants in accordance with rules 111, 119A, or 119B.

…

Subchapter 4.4 – Modelling

107A Definitions

In this Subchapter 4.4 —

(a) "**Modelling Information**" means a software model, its inputs and assumptions, and any other information provided, or required or directed to be provided, for the purposes of this Subchapter 4.4 or the modelling requirements of the Harmonised Technical Rules.

…

108A ISO to develop and Maintain a Reduced Power System Model

(1) The ISO must in accordance with the Power System Modelling Procedure develop and Maintain a reduced version of the Power System Model (the "**Reduced Power System Model**"), which —.

(a) has Confidential Information removed or protected, and

(b) is sufficient for use by a Registered NSP or Prospective Registered NSP to conduct the studies, the modelling and the assessments necessary to ensure its or its Registered NWIS Network compliance with all applicable Rules and Procedures.

(2) The ISO may in accordance with the Power System Modelling Procedure develop bespoke versions of the Reduced Power System Model from time to time to be provided to a Recipient under rule 114A or 114B that may contain Confidential Information owned by the Recipient but not Confidential Information that is not owned by the Recipient.

109 ISO may use Power System Models

Subject to these Rules (including Subchapter 4.5), the ISO may use the Power System Model and the Reduced Power System Model as it sees fit in performing its functions under these Rules.

110 Registered NSP to Develop and Maintain a Network Model

(1) Each Registered NSP must in accordance with the Power System Modelling Procedure and the NSP's own Network Modelling Procedure ~~D~~develop and Maintain an accurate software model of its Network (the "**Network Model**"), which —

(a) incorporates the Equipment Limits and Security Limits set out in the Standing Data, the Frequency Operating Standards and the other parameters for remaining Inside the Technical Envelope applicable to the Network; and

(b) for each Registered Facility on the Network, and each other Facility which meets the threshold specified for this purpose in the NSP's Network Modelling Procedure — include a mathematical model of the Facility, including the impact of its control systems and protection systems on Security and Reliability within the Network.

(2) The Network Model must be compatible with the Power System Model.

(3) The Network Model must be sufficient to Enable the Registered NSP to —

(a) develop a Limit Advice under Subchapter 9.1; and

(b) comply with its obligations under the Access Code and Subchapter 9.2; and

(c) perform its other functions under these Rules.

(5) A Registered NSP must, in accordance with the Power System Modelling Procedure, Promptly —

(a) provide its Network Model to the ISO; and

(b) provide the ISO with a list of all Confidential Information contained within the Network Model, with an explanation why each information should be treated as Confidential Information.

(6) The Network Model may only be disclosed by the ISO to another party with the permission of the relevant Registered NSP, and rule 303 {pre-disclosure process} applies.

…

110A Registered NSP to develop and Maintain a Reduced Network Model

(1) Each Registered NSP must, in accordance with the Power System Modelling Procedure, develop and Maintain a version of its Network Model for inclusion in the Reduced Power System Model (a "**Reduced Network Model**"), which —

(a) may remove or protect Confidential Information via encryption or other means; and

(b) must meet the requirements in rule 110A(3).

(2) The Reduced Network Model may be included in the Reduced Power System Model that the ISO provides to a Registered NSP under rule 119A(2)(b), or to a Prospective Registered NSP under rule 119B(2), and rule 303 {pre-disclosure process} does not apply.

(3) The Reduced Network Model must —

(a) be compatible with the Power System Model and the Reduced Power System Model; and

(a) be sufficient for use for access and connection related purposes; and

(b) satisfy any functional or technical requirements specified for a Reduced Network Model in the Power System Modelling Procedure.

(5) A Registered NSP must, in accordance with the Power System Modelling Procedure, Promptly but no later than the time specified in the Power System Modelling Procedure —

(a) provide its Reduced Network Model to the ISO; and

(b) provide the ISO with a description of any information that is in its Network Model but is not in its Reduced Network Model and the reasons why it is not included; and

(c) provide the ISO with a description of any information that is protected in its Reduced Network Model, the means by which it is protected, and the reasons why it is protected.

(6) If the ISO determines that a Reduced Network Model does not satisfy a requirement in rule 110A(3), the ISO may, in accordance with the Power System Modelling Procedure, require the relevant Registered NSP to make revisions to the Reduced Network Model and provide it to the ISO by the time prescribed in the Power System Modelling Procedure.

110B Prospective Registered NSP to provide a Network Model to the ISO

(1) If the Power System Model, at the time an application by a Prospective Registered NSP is submitted to the ISO under rule 114B(1), does not include a Network Model of a Network or Networks relevant to the application for which the Prospective Registered NSP is the NSP, the Prospective Registered NSP must, in accordance with the Power System Modelling Procedure, develop and provide to the ISO an accurate Network Model, which —

(a) incorporates the Equipment Limits and Security, the Frequency Operating Standards and any other parameters required to remain Inside the Technical Envelope applicable to the Network; and

(b) for each Facility which meets the threshold specified for inclusion in the Power System Modelling Procedure — includes a mathematical model of the Facility, including the impact of its control systems and protection systems on Security and Reliability within the Network.

(2) The Network Model must be compatible with the Power System Model.

(3) The Network Model must satisfy any functional or technical requirements specified for a Reduced Network Model in the Power System Modelling Procedure.

(4) The Network Model may only be disclosed by the ISO to another party with the permission of the Prospective Registered NSP, and rule 303 {pre-disclosure process} applies.

111 ISO may assist a Registered NSP to develop and Maintain its Network Model

(1) Subject to its resourcing including Subchapter 4.5, and to rule 120, the ISO may provide information to assist a Registered NSP to develop and Maintain its Network Model~~, including, if requested, giving the NSP up-to-date software models of other nNetworks and the fFacilities Connected to them~~.

(2) It remains the Registered NSP's responsibility to comply with rule 110 and the Harmonised Technical Rules~~, whatever the ISO does or does not do under rule 111(1)~~.

111A ISO may assist a Prospective Registered NSP to develop a Network Model

(1) Subject to its resourcing, including Subchapter 4.5, and to rule 120, the ISO may assist a Prospective Registered NSP to develop a Network Model in accordance with rule 110B.

(2) It remains the Prospective Registered NSP's responsibility to comply with rule 110B and the Harmonised Technical Rules.

112 NSP may use Network Model

Subject to these Rules and the Access Code, ~~the~~ a Registered NSP ~~or a Prospective Registered NSP~~ may use ~~the~~its own Network Model in performing its functions under the Access Code and these Rules, and it is a function of ~~the~~ an NSP to do so.

113 NSP modelling functions in HTR apply

The ISO's functions under this Subchapter 4.4 are in addition to, and do not limit, but may be used to support, an NSP's modelling functions under the Harmonised Technical Rules.

114 ISO to model and consult when NSP requests it

(1) If these Rules require or permit the Registered NSP to undertake modelling, then —

(a) if rule 50 requires it — the Registered NSP must; and

(b) for a Covered Network, if an Access Seeker reasonably requests it in accordance with the Access Code — the Covered NSP must; and

(c) otherwise — the Registered NSP may,

request the ISO to undertake modelling and other analyses, and engage in reasonable consultation, to support or supplement the Registered NSP's analyses.

(2) A request under rule 114(1) must be reasonable, and must be made in accordance with the Power System Modelling Procedure, and be accompanied by whatever information the Procedure requires the request to be accompanied by.

(3) Subject to rule 114(4), the ISO will undertake the requested modelling in accordance with the Power System Modelling Procedure. However, the ISO may in each case determine in accordance with that Procedure what scale and scope of modelling and consultation is appropriate.

(4) If the ISO determines that any information provided to it by a Registered NSP under this rule 114 is incorrect, or does not comply with the Power System Modelling Procedure, the ISO (after first consulting with the Registered NSP) may Direct the Registered NSP as to what corrected or further information the ISO requires.

114A Use of Reduced Power System Model by Registered NSPs

(1) A Registered NSP may, in accordance with the Access and Connection Procedure, make a request to the ISO to be provided with access to the Reduced Power System Model for the purposes of performing a function of the Registered NSP under these Rules, the Access and Connection Procedure or the Pilbara Networks Access Code.

(2) The ISO must grant a request made under rule 114A(1).

(4) The Access and Connection Procedure may specify —

(a) the process for submitting a request under rule 114B(1); and

(b) the information to be contained in the request; and

(c) the fee to be paid to the ISO by the Registered Participant.

(6) A Registered NSP provided with access to a Reduced Power System Model under rule 114A(2) must, if requested by the ISO, provide the ISO with the results of the modelling the Registered NSP undertakes.

(7) The ISO must, in accordance with the Access and Connection Procedure, publish details of requests granted by the ISO under rule 114A(2).

114B Use of Reduced Power System Model by Prospective Registered NSPs

(1) A person (in this rule 114B, the "**Applicant**") may apply to the ISO to be listed as a "**Prospective Registered NSP**" in order to access the Reduced Power System Model, and pay the fee specified in the Access and Connection Procedure.

(2) The ISO must Prompty approve or reject an application made under rule 114B(1) and may only reject an application if ISO considers that the Applicant does not have a genuine reason to become a Prospective Registered NSP or to access the Reduced Power System Model.

(3) If an application made under rule 114B(1) is approved, the ISO must provide the Prospective Registered NSP with access to the Reduced Power System Model for the purposes of performing a function of the Applicant under these Rules, the Access and Connection Procedure, or the Pilbara Networks Access Code.

(4) A Prospective Registered NSP must comply with all applicable rules, including but not limited to —

(a) rule 110B(1) to develop a Network Model and provide it to the ISO;

(b) this rule 114B; and

(c) Subchapter 11.2 {Confidential Information}.

(6) The Access and Connection Procedure may specify —

(a) the process for submitting an application under rule 114B(1);

(b) the information to be contained in the application; and

(c) the fee to be paid to the ISO by the Applicant.

(6) A Prospective Registered NSP that has been provided with access to the Reduced Power System Model under rule 114B(3) must, if requested by the ISO, provide the ISO with the Modelling Information and the results of any modelling the Prospective Registered NSP undertakes.

(7) The ISO must, in accordance with the Access and Connection Procedure, publish details of requests granted by the ISO under rule 114B(3).

…

120 ~~Confidentiality in modelling~~Provision of Modelling Information to ISO

~~{Overview of this rule 120 — A complete, current and accurate Power System Model is a vital requirement for, among other things, Security, Reliability and effective access. This rule Enables the ISO to access all information it requires for this purpose, regardless of its confidentiality. However, once in the ISO's hands, the information remains protected by Subchapter 11.2.}~~

(1) [BLANK]~~In this rule 120, "Modelling Information" means a software model, its inputs and assumptions, and any other information provided, or required or directed to be provided, for the purposes of this Subchapter 4.4 or the modelling requirements of the Harmonised Technical Rules.~~

(2) A Rules Participant must comply with an obligation to provide Modelling Information or modelling results to the ISO whether or not the information is confidential or commercially sensitive, including if another person is the Information Owner.

(3) Any of the following that involves a use or disclosure of Confidential Information of any Information Owner is a use or disclosure of confidential or commercially sensitive information that is authorised by these Rules —

(a) provision of a Reduced Network Model to the ISO by a Registered NSP; or

(b) disclosure to, and use of a Reduced Power System Model by a Registered NSP or a Prospective Registered NSP; or

(c) the use of a Reduced Network Model in the preparation of a Reduced Power System Model.

{Rule 305 protects the Rules Participant for this disclosure, if it owes another person a duty of confidentiality in respect of the Modelling Information.}

~~(3) To the extent any Modelling Information provided to the ISO is Confidential Information, Subchapter 11.2 applies —~~

~~(a) in respect of the ISO's use and disclosure of the information; and~~

~~(b) to any Recipient to whom the ISO directly or indirectly discloses the information.~~

~~(4) If —~~

~~(a) the ISO provides a software model to an NSP under rule 111; and~~

~~(b) the use of the model may disclose confidential Modelling Information which has been disclosed to the ISO by a Rules Participant,~~

~~then —~~

~~(c) if the Rules Participant or the Information Owner reasonably request the ISO to endeavour to protect the information as described in this rule 120(4) — the ISO must; and~~

~~(d) otherwise — the ISO on its own initiative may, endeavour to provide the model to the NSP in a manner which performs appropriately but does not disclose Confidential Information.~~

~~{Example — In providing a model of Network A to the NSP of Network B, the ISO might provide it as an encrypted 'external grid representation' module which simulates Network A's performance at the Interconnector, without disclosing how Network A is configured or what facilities may be Connected to it.}~~

~~(5) Rule 120(4) limits rule 299 {Permitted disclosure in performance of a function}.~~

121 ISO to Develop Power System Modelling Procedure

…

(6) The Power System Modelling Procedure may specify matters relating to the development and Maintenance of a Reduced Network Model, including —

(a) any functional or technical requirements a Reduced Network Model must meet in addition to those specified in rule 110A;

(b) the requirements a Reduced Network Model must satisfy to be sufficient for use in access and connection related purposes; and

(c) the process by which the ISO may determine that a Reduced Network Model does not satisfy one or more requirements of Rule 110A and the process by which a Registered NSP must respond to such a determination.

…

Schedule 6: Changes to Pilbara Advisory Committee membership

Explanatory Note

Clause A2.3.5 is amended to remove the requirements that independent members representing the interest of contestable customers and small-use customers on the Pilbara Advisory Committee must be nominated by the Minister.

Appendix 2 – Rule and Procedure change

{Note on clause numbering — The Rule Change and Procedure change regimes described in this Appendix and in the WEM Rules are similar but not identical. To help the reader find comparable clauses in the two regimes, this Appendix uses similar numbering.}

Sub-appendix 2.1 – Rule and Procedure change governance

…

Who is to be members of the PAC

A2.3.5 Subject to clause A2.3.13, the Pilbara Advisory Committee must comprise —

(a) at least 1 and not more than 6 members representing Rules Participants not listed in the following paragraphs;

(b) at least one independent member ~~nominated by the Minister~~ to represent the interests of contestable customers;

(c) for each Registered NSP, a member to represent the NSP;

(d) for each Excluded NSP, if the NSP so chooses, a member to represent the NSP;

(e) at least one independent member ~~nominated by the Minister~~ to represent the interests of small-use customers;

(f) [blank]

(g) a member to represent the ISO;

(h) [blank]

(i) an Independent Chair, to be appointed by the Minister under clause A2.3.8A.

A2.3.5A [Blank]

A2.3.5B The same Entity cannot be represented by more than one member on the Pilbara Advisory Committee simultaneously.

A2.3.5C Candidates for appointment under clause A2.3.5(c), (d) and (g) must be proposed to the Coordinator by the Entity the candidate is to represent.

A2.3.6 The Minister may appoint a representative to attend Pilbara Advisory Committee meetings as an observer.

A2.3.7 The Authority may appoint a representative to attend Pilbara Advisory Committee meetings as an observer.

A2.3.7A The Coordinator or the Independent Chair of the Pilbara Advisory Committee may invite a person to attend Pilbara Advisory Committee meetings as an observer, either for a specified meeting or meetings or until further notice.

A2.3.8 The Coordinator may, after consulting with the Independent Chair, appoint members of the Pilbara Advisory Committee. In the case of members to be appointed under clause A2.3.5(c), (d), and (g), the Coordinator cannot appoint a person who has not been proposed to the Coordinator under rule A2.3.5C by the Entity the candidate is to represent.

…

Schedule 7: Updated WA Voltage and Frequency Regulations [Issue 4] and review of clause 2.2.2(c) (varying voltage operating standard by agreement) [Issue I2025.1]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 4' in the HTR Workbook. An issue paper was presented on 14 November 2024. Further drafting instructions from the Issue Lead were provided on 18 September 2025. 'Issue 2025.1' was presented on 31 July 2025. An issue paper was presented on 10 September 2025.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

Clauses 2.2.2(a),3.4.2(c) and Figure 2.1 are amended and clauses 2.2.10(b) and Figure 2.2 have been added to align the Harmonised Technical Rules with the new voltage requirements in clause 55B of the *Electricity Industry (Electricity System and Market) Regulations 2004*.

New clause 2.2.2(c)(1) has been introduced to clarify that a variation in voltage operating standards negotiated between an NSP and a controller does not impact the technical envelope as defined in the Pilbara Networks Rules or the operating standards under the Harmonised Technical Rules.

2.2.2 Steady State Power Frequency Voltage

(a) Except as a consequence of a *non-credible contingency event*, the minimum steady state *voltage* on the *transmission system* and those parts of the *distribution system* operating at *voltages* of 6.6 kV and above must be 90% of nominal *voltage* and the maximum steady state *voltage* must be 110% of nominal *voltage*. For those parts of the *distribution system* operating at *low voltage*, the steady state *voltage* must be:

~~(1) ± 6% of the nominal *voltage* during normal operating state,~~

~~(2) ± 8% of the nominal *voltage* during *maintenance conditions*,~~

~~(3) ± 10% of the nominal *voltage* during *emergency conditions*.~~

(1) for single-phase connections — between 207 V and 254 V during normal operating conditions as defined in the *Pilbara networks rules*; or

(2) for three-phase connections — between 360 V and 440 V during normal operating conditions as defined in the *Pilbara networks rules*.

(b) Step *changes* in steady state *voltage* levels resulting from switching operations must not exceed the limits given in Table 2.3.

(c) Where more precise control of *voltage* is required than is provided for under subclause 2.2.2(a), a target range of *voltage* magnitude at a *connection point*, may be agreed with a *controller* and specified in an *access contract*. This may include different target ranges under normal and post-contingency conditions (and how these may vary with *load*). Where more than one *controller* is supplied at a *connection point* such that independent control of the *voltage* supplied to an individual *controller* at that *connection point* is not possible, a target must be agreed by all

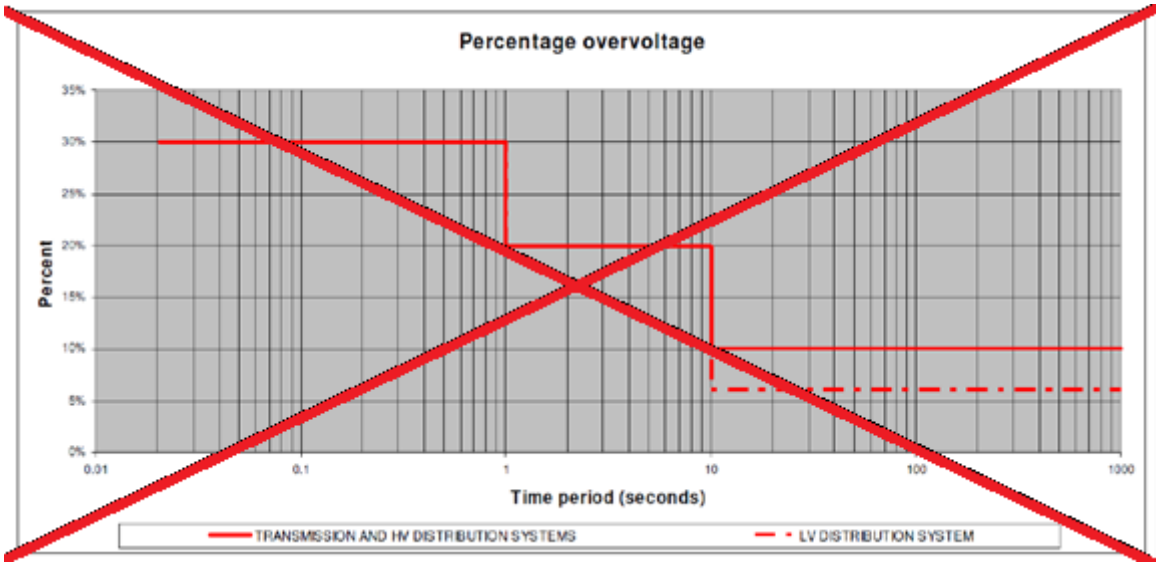
relevant *controllers* and the *NSP*. Where *voltage* magnitude targets are specified in an *access contract*, *controllers* should allow for short-time variations within 5% of the target values in the design of their *equipment*.

(1) A variation of *voltage* operating standards made under this subclause does not impact the power system operating inside the technical envelope as defined in the *Pilbara networks rules*, nor alters the fundamental *voltage* operating standards established under these *harmonised technical rules*.

…

2.2.10 Temporary over-voltages

(a) As a consequence of a *credible contingency event*, the power *frequency voltage* at all locations in the *power system* must remain within the over-*voltage* envelope shown in Figure 2.1.



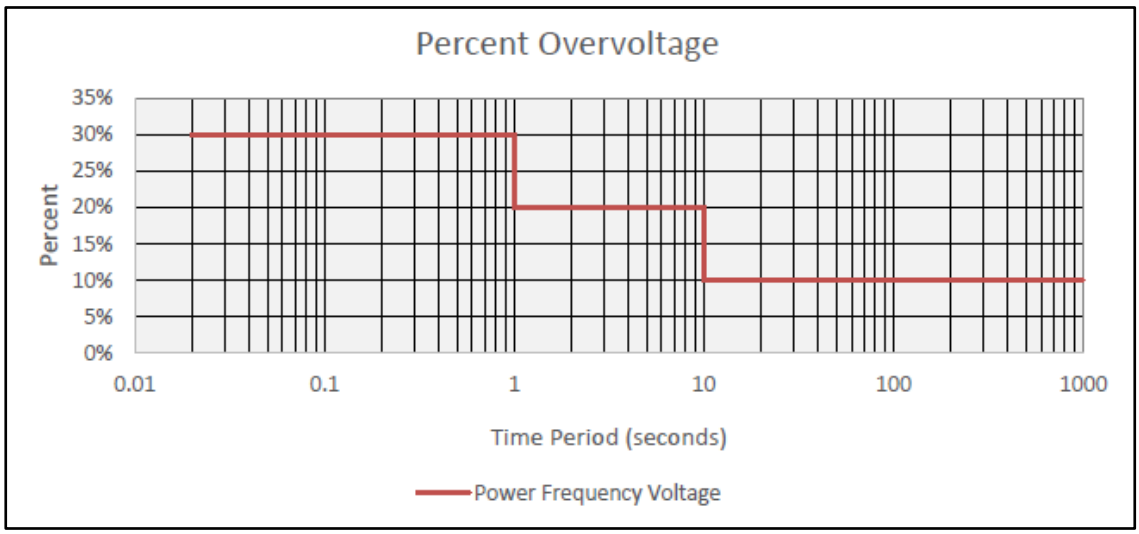


Figure 2.1 – Percentage Overvoltage Envelope

{Note: The percentage overvoltage levels refers to the percentage above the nominal voltage.}

(b) As a consequence of a switching event or *credible contingency event*, the power frequency voltage at all locations in the *low voltage distribution system* must remain within the over-voltage envelope shown in Figure 2.2.

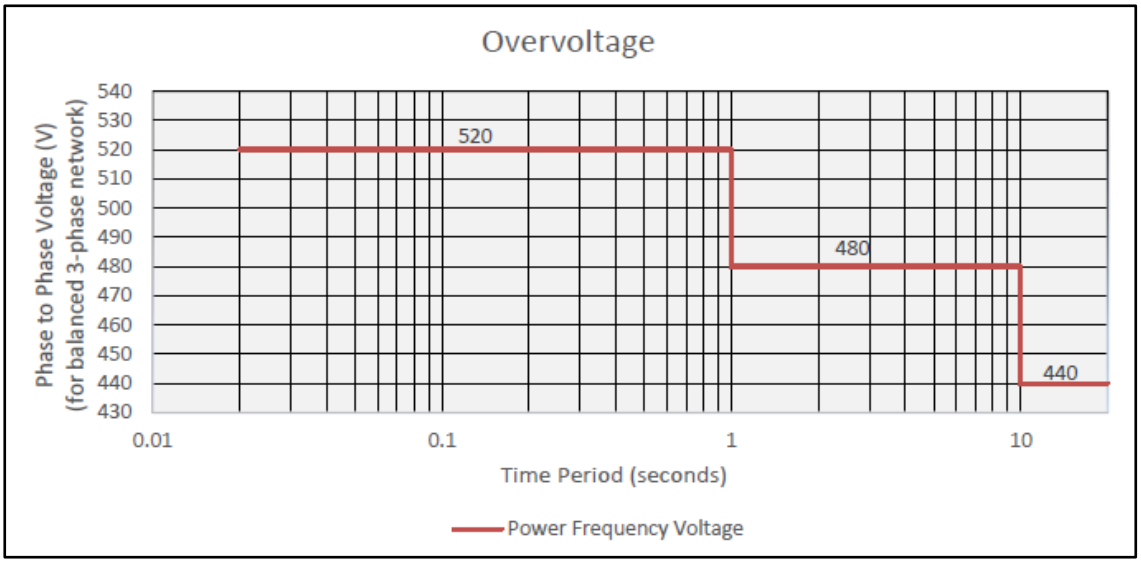


Figure 2.2 – Overvoltage Envelope – Low Voltage Distribution System

…

3.4.2 Categorisation of facilities

…

(c) In this clause, *connection points* for small *power stations* are characterised as:

(1) *medium voltage connected*: 3 phase, 6.6 kV, 11 kV, 22 kV or 33 kV; or

(2) *low voltage connected*: ~~1, 2 or 3 phase plus neutral, 240 V or 415 V.~~ 1, 2 or 3 phase plus neutral, 230V or 400V.

…

Schedule 8: Review of HTR cl 3.7 (Requirements for the connection of storage) [Issue 8]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 8' in the HTR Workbook. An Issue Paper was presented on 9 October 2025. Further drafting instructions were provided on 20 and 30 October 2025.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

Clause 3.7 provides for the determination of requirements by the ISO, in collaboration with the NSP, for the connection of storage facilities, defined as Storage Works in the Pilbara Networks Rules. By delegating the responsibility to determine performance requirements for storage works to the ISO, clause 3.7 does not provide for the same level of transparency, consistency, and rigour as other user facilities including large generating units (clause 3.3), small generating units (clause 3.4), LV connected inverters (clause 3.5), and loads (clause 3.6).

A suite of amendments to clauses 3.3 and 3.7 are proposed to support the participation and increasing prevalence of Battery Energy Storage Systems and inverter-based generating units:

- Storage works is included in definitions in the HTR.
- Clauses 3.3.3.3(a) is amended so that, for the purposes of the connection of storage works, the requirements for generating units responding to power system disturbances also apply to storage works.
- Similar changes to clause 3.3.3.4 will mean the requirement of a generating unit to be capable of a sudden reduction in active power will also apply to storage works.
- Similar changes to clause 3.3.4.5 will apply the technical rules for a unit's voltage control system to storage works.
- Similar changes to clause 3.3.3.5(a) apply ramping rate limits to storage works.
- Amendments to clause 3.3.4.4(a) expand automatic variable speed control requirements to all generating unit control systems, not just turbine control systems. Amendments to clause 3.3.4.4(e) expand the applicability of rules on control range for dispatchable generating units to all generating units, not just synchronous generating units. Both changes will make those rules applicable to generating units that are storage works.
- Clause 3.3.4.4(f)(1) is amended so that non-synchronous generating units are covered by rules establishing a rate of response under frequency control provisions.
- The current clause 3.7 states the Harmonised Technical Rules apply to a storage facility as a generating unit in respect its injections only. Amendments to clause 3.7 allow that storage works may be always treated as a generating unit, and that any technical requirements applied when a storage works is operating at a generating unit are dependent on the state of charge of the storage works.
- Clause 5.2.3(e) is amended to ensure that the responsibility of a controller to notify an NSP when a generating unit is unable to respond in accordanance to clause 3.3.4.4 does not apply when the storage works does not possess the relevant state of charge to do so.

1.5 Interpretation

…

statutory instruments	means all relevant instruments made under a *written law* including all *directions*, notices, orders and other instruments given or made under a *written law*.

storage works	is defined in the *Pilbara networks rules*.
substation	means a *facility* at which lines are switched for operational purposes, and which may include one or more *transformers* so that some *connected* lines operate at different nominal *voltages* to others.

…

3.3.3.3 Generating unit response to disturbances in the power system

(a) **Overview**

The following are design requirements for *generating units* and their auxiliary systems for continuous uninterrupted operation while being subjected to off-nominal *frequency* and *voltage* excursions. Continuous uninterrupted operation is defined in subclause 3.3.3.3(h). For the purposes of clause 3.7, the requirements of this clause apply to *storage works*.

{Note: Some of these requirements may be relaxed when it is considered that failure to comply would not have a material impact on safety or *power system* performance. A *generator* seeking a relaxation of the requirements must apply for an exemption from the *Rules*.}

(b) **Immunity to frequency excursions**

A *generating unit* and a *power station* in which the *generating unit* is located must be capable of continuous uninterrupted operation within the *power system frequency* envelope specified in Figure 3.4. Operation for a period of at least 20 seconds is required each time the *frequency* is below 47.5 Hz. Operation for a period of at least 6 seconds is required each time the *frequency* is above 52 Hz. Below 47 Hz and above 52.5 Hz, instantaneous *disconnection* of *generating units* is permitted.

…

(c) **Immunity to voltage excursions**

(1) A *generating unit* and the *power station* in which the *generating unit* is located must be capable of continuous uninterrupted operation for *network* faults which cause the *voltage* at the *connection point* to drop below the nominal *voltage* for a period equal to the *circuit breaker failure* fault clearing time to clear the fault plus a safety margin of 30 ms, followed by a period of 10 seconds where the *voltage* may vary in the range 80% to 110% of the nominal *voltage,* and a subsequent return of the *voltage* within the range 90 to 110% of the nominal *voltage.*

(2) Notwithstanding the requirements of subclause 3.3.3.3(c)(1) no *generating unit* shall be required to be capable of continuous uninterrupted operation where the *voltage* at the *connection point* falls below the envelope shown in Figure 3.5.

…

(d) **Immunity to rate-of-change of frequency**

A *generating unit* and the *power station* in which the *generating unit* is located must be capable of continuous uninterrupted operation for any rate-of-*change*-of-*frequency* of up to 4 Hz per second.

(e) **Immunity to high speed auto reclosing**

A *generating unit* and the *power station* in which the *generating unit* is located must be capable of continuous uninterrupted operation for *voltage* transients caused by high speed auto-reclosing of *transmission lines* irrespective of whether or not a fault is cleared during a reclosing sequence. See Figure 3.6 for details of the *low voltage* ride through requirement during auto-reclose operation.

…

(f) **Post-fault reactive power of a power station with non-synchronous generating units**

After fault clearing, the *power station* in which a non-*synchronous generating unit* is located must not absorb *reactive power* from the *transmission system* or the *distribution system*. Any pre-fault absorption of *reactive power* has to be terminated within 200 ms after clearing of the fault. The absorption is permitted to recommence, if required by the applicable *voltage* control strategy, after the postfault *voltages* stabilise for at least 60 seconds at an above nominal value.

{Note: This requirement is intended for under-*voltage* situations where a *generator* is potentially exacerbating the problem.}

(g) **Post fault voltage control of a connection point**

Each *generating unit* must be fitted an *active power* output *controller*, such as a governor, and a *voltage* regulator so that, following the occurrence of any *credible contingency event* and *changed power system* conditions after *disconnection* of the faulted element, the *generating unit* must be capable of delivering to the *network active power* and *reactive power* sufficient to ensure that the *connection point voltage* is within the range for continuous uninterrupted operation for that *generating unit*.

(h) **Continuous uninterrupted operation**

For the purposes of this clause, a *generating unit* is considered to remain in continuous uninterrupted operation if:

(1) the generating unit is not disconnected from the network due to protection system operation;

(2) the *active power* output returns to the *generating unit's* pre-fault electric power output within 200 milliseconds after the *voltage* has returned to between 80% to 110% of nominal *voltage*. In making this assessment allowances may be made for:

(A) any variation in *active power* output for non-*synchronous generating units* due to variation in the primary source of *energy*; and

(B) any variation in *active power* output of *synchronous generating units* due to any reduction in the *power system frequency* in accordance with the capability of the *generating unit* as notified to the *NSP*.

(3) the *reactive power* control mode in which the *generating unit* was operating prior to the *credible contingency event* occurring does not *change*, unless it is required by subclause 3.3.3.3(f).

…

3.3.3.4 Sudden reduction in active power requirement

A *generating unit* must be capable of continuous uninterrupted operation as defined in subclause 3.3.3.3(h) during and following a sudden reduction in required *active power generation* imposed from the *power system,* provided that the reduction is less than 30% of the *generator machine's nameplate rating* and the required *active power generation* remains above the *generating unit's* notified minimum *active power generation* capability. For the purposes of clause 3.7, the requirements of this clause apply to *storage works*.

3.3.3.5 Ramping rates

(a) A *dispatchable generating unit*, in a thermally stable state, must be capable of increasing or decreasing *active power generation* in response to a manually or remotely initiated order to *change* the level of *generated active power* at a rate not less than 5% of the *generator machine's nameplate rating* per minute. For the purposes of clause 3.7, the requirements of this clause apply to *storage works*.

(b) A non-*dispatchable generating unit* must not increase or decrease its *active power generation* at a rate greater than 15% of the *generator machine's nameplate rating* per minute.

…

3.3.4.4 Frequency control

(a) All *generating units* must have an automatic variable speed control characteristic. ~~*Turbine*~~ *Generating unit control systems* must include *facilities* for both *frequency* and *load control.*

(b) *Generating units* must be capable of *operation* in a mode in which they will automatically and accurately alter *active power* output to allow for *changes* in associated *load*s and for *changes* in *frequency* of *the transmission and distribution system* and in a manner to sustain high initial response.

(c) A *generator* must, operate a *generating unit* in the mode specified in subclause (b) unless instructed otherwise by the *NSP* or the *ISO*, as the case requires.

(d) **Dead band**

The dead band of a *generating unit* (the sum of increase and decrease in *power system frequency* before a measurable *change* in the *generating*

unit's active power output occurs) must be less than 0.05 Hz, unless an adjustable dead band is agreed to in the *access contract*.

(e) **Control range**

(1) *For dispatchable generating units:*

(A) The overall response of a ~~*synchronous* generating unit~~ for *power system frequency* excursions must be settable and be capable of achieving an increase in the *generating unit's active power* output of not less than 5% for a 0.1 Hz reduction in *power system frequency* (4% droop) for any initial output up to 85% of rated output.

(B) A ~~*synchronous* generating unit~~ must also be capable of achieving a reduction in the *generating unit's active power* output of not less than 5% for a 0.1 Hz increase in system *frequency* provided this does not require operation below the *technical minimum*.

(C) For initial outputs above 85% of rated *active power* output, a *generating unit's* response capability must be included in the relevant *access contract*, and the *generator* must ensure that the *generating unit* responds in accordance with that *access contract*.

(D) *Thermal generating units* must be able to sustain *load changes* of at least 10% for a *frequency* decrease and 30% for a *frequency* increase if *changes* occur within the above limits of output.

(2) For *non-dispatchable generating units, a generating unit* must be capable of achieving a reduction the *generating unit's active power* output for an increase in system *frequency,* provided the latter does not require operation below *technical minimum*.

(f) **Rate of response**

~~(1) For *dispatchable generating units*, for any *frequency* disturbance, the *generating unit* must achieve at least 90% of the maximum response expected according to the droop characteristic within 6 seconds for *thermal generating units* or 30 seconds for hydro *generating units* and the new output must be sustained for not less than a further 10 seconds.~~

(1) For *dispatchable generating units*, for any *frequency* disturbance, the *generating unit* must achieve at least 90% of the maximum response expected according to the droop characteristics within:

(A) 6 seconds for *thermal generating units*;

(B) 30 seconds for hydro *generating units*;

(C) 2 seconds for non-synchronous *generation units*,

and the new output must be sustained for not less than a further 10 seconds.

(2) For non-dispatchable generating units, for any frequency disturbance, a *generating unit* must achieve at least 90% of the maximum response expected within 2 seconds and the new output must be sustained for not less than a further 10 seconds.

3.3.4.5 Voltage control system

{Note: The overriding objective of a *generating unit's voltage control system* is to maintain the specified *voltage* range at the *connection point*.

…

(j) For the purposes of clause 3.7, the requirements of this clause for non-*synchronous generating units* apply to *storage works*.

…

3.7 Requirements for connection of storage

(a) The *NSP* and the *ISO* must collaborate regarding, and the *ISO* may determine, the requirements for connection of *storage* ~~*facilities*~~ *works* to the *network*, having regard to:

(1) the system security objective; and

(2) *GEIP*; and

(3) the Pilbara electricity objective; and

(4) subject to paragraphs 3.7(a)(1), 3.7(a)(2) and 3.7(a)(3), the objective that these *harmonised technical rules* and the *Pilbara networks rules* be technology-neutral wherever practicable.

(b) Without limiting clause 3.7(a), the *NSP* and *ISO* may choose to apply these *harmonised technical rules* to a *storage* ~~*facility*~~ *works* by treating it:

(1) ~~in respect of its *injections* —~~ as a *generating unit*; and

(2) in respect of its withdrawals — as ~~consumer equipment~~ *consumer equipment*.

(c) When these *harmonised technical rules* are applied to *storage works* as a *generating unit* under clause 3.7(b)(1), compliance with technical requirements apply only to the extent permitted by the state of charge of the *storage works* at the relevant time.

…

5.2.3 Controller Obligations

(a) A *controller* must ensure that only appropriately qualified and competent persons operate *equipment* that is directly connected to the *network* through a *connection point*.

(b) A *controller* must co-operate with any review of operating incidents undertaken by the *NSP* under clause 5.6.3.

(c) A *controller* must co-operate with and assist the *NSP* and the *ISO* (and, if applicable, its delegate) in the proper discharge of the *power system* operation and co-ordination responsibilities.

(d) A controller must operate its *facilities* and *equipment* in accordance with law (including the *Pilbara networks rules* and these rules), and (subject to the foregoing and any *access contract*) good electricity industry practice.

(e) A *controller* must notify the *NSP*, prior to a *generating unit* being operated in a mode (e.g. "turbine-follow" mode) where the *generating unit* will be unable to respond in accordance with clause 3.3.4.4, excluding a *controller* of *storage works* where the state of charge does not permit the required response.

…

…

Schedule 9: Inverter Dynamic Performance [Issues 10 and 11]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issues 10 and 11' in the HTR workbook. An issue paper was presented on 14 November 2024 and 31 July 2025. Further drafting instructions were provided 21 October 2025.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

New definitions for 'disturbance stability' 'generating system' and 'non-synchronous generating unit' have been introduced to clause 1.5. The definition of 'small disturbance rotor angle stability' has been removed.

The definition of transient stability in clauses 2.2.7 and 2.2.8 have been amended to be technology agnostic in their application.

Clauses 2.2.8(a) – (c) have been removed and replaced with Table 2.8, outlining the disturbance stability criteria for small and large disturbances respectively.

Clauses 3.3.1(d) and subclause (1) have been amended to align them with changes to clauses 2.2.7 and 2.2.8.

Clauses 3.3.1(i) has been introduced to require all generating systems to ensure their connection does not degrade power system dampening.

Clause 3.3.3.3(f) has been introduced to amend the conditions under which power stations with non-synchronous generating units may absorb reactive power after disturbances in the power system.

Clause 3.3.3(g) has been amended to fix a minor typographical error.

1.5 Interpretation

distribution system	is defined in the *Act*
disturbance stability	means the ability of the *power system* to maintain *synchronism* under *small disturbances* or *large disturbances*.
dynamic performance	means the response and behaviour of *networks* and *facilities* which are connected to the *networks* when the normal operating state of the *power system* is disturbed.

…

generated	in relation to a *generating unit* — means the amount of electricity produced by the *generating unit* as measured at its terminals.
generating system	in relation to a *generating unit* – a system comprising one or more *generating units*.
generating unit	is defined in the *Pilbara networks rules*.

…

non-dispatchable generating unit	means a *generating unit* that in its satisfactory normal operating state is not capable of closely controlling its real power output.
non-synchronous generating unit	in relation to a *generating unit* – a *generating unit* that is not a *synchronous generating unit*.
NSP	is defined in the *rules*, and does not include the *NSP* of an *excluded network*.

…

small disturbance	means a disturbance sufficiently small to permit the linearization of system equations for the purposes of analysis. The resulting system response involves small excursions of system variables from their pre-disturbance values. *Small disturbances* may be caused by routine switching (for example, line or capacitor), *transformer* tap *changes*, *generating unit* AVR set point *changes*, *changes* in the *connected load*, etc.
~~**small disturbance rotor angle stability**~~	~~means the ability of the *power system* to maintain *synchronism* under *small disturbances*.~~
small use consumer	means a *consumer* that consumes less than 160 MWh of electricity per annum.

…

transformer tap position	means where a tap changer is fitted to a *transformer*, each tap position represents a *change* in *voltage* ratio of the *transformer* which can be manually or automatically adjusted to *change* the *transformer* output *voltage*. The tap position is used as a reference for the output *voltage* of the *transformer*.
transient ~~rotor angle~~ stability	means the ability of the *power system* to maintain *synchronism* when subjected to severe disturbances, for example a short circuit on a nearby *transmission line*. ~~The resulting system response involves large excursions of *generating unit* rotor angles and is influenced by the non-linear power-angle relationship.~~
transmission	means the functions performed by a *transmission system*, including transporting, and controlling the transportation of, electricity, and the provision of "services" (as defined in the Act).

…

2.2.7 Transient ~~rotor angle~~ stability

All *generating units* connected to the *transmission system* and *generating units* within *power stations* that are *connected* to the *distribution system* must remain in *synchronism* following a *credible contingency event*.

2.2.8 Oscillatory ~~rotor angle~~ stability

System oscillations originating from system electro-mechanical characteristics, electromagnetic effect or non-linearity of system components, and triggered by ~~any~~ either a *small disturbance* or *large disturbance* in the *power system*, must remain within the ~~*small* disturbance *rotor angle*~~ *stability* criteria and the *power system* must return to a stable operating state following the disturbance. The ~~*small* disturbance *rotor angle*~~ *stability* criteria are~~:~~ set out in Table 2.8.

~~(a) The *damping ratio* of electromechanical oscillations must be at least 0.1.~~

~~(b) For electro-mechanical oscillations as a result of a *small disturbance*, the *damping ratio* of the oscillation must be at least 0.5.~~

~~(c) In addition to the requirements of subclause 2.2.8(a), the *halving time* of any electro-mechanical oscillations must not exceed 5 seconds.~~

Table 2.8 – Disturbance stability criteria

Disturbance	Damping Ratio	Halving Time
Small disturbance	At least 0.5	Not greater than 0.5s
Large disturbance	At least 0.1	Not greater than 0.5s

…

2.3.1 Frequency control

…

(c) *NSPs* may require commercial and industrial *consumers* to make a portion of their *load* available for automatic under-*frequency* or under*voltage load shedding* or both and may also require a commercial or industrial *consumer* to provide control and *monitoring equipment* for the *load shedding* facilities. The amount of *load* to be available for shedding and the frequencies or *voltages* or both at which *load* must be shed must be negotiated between the *NSP* and the *controller* or, failing agreement between them, must be as determined by an *access dispute arbitration* or as specified by the *ISO* (consistent with Table ~~2.9~~ 2.10 for the *NWIS* only), and must be specified in the relevant *access contract*.

…

2.3.9 Assessment of power system performance

(a) The *NSP* must monitor the performance of the *power system* on an ongoing basis and ensure that the *networks* are *augmented* as necessary so that the *power system* performance standards specified in clause 2.2 continue to be met irrespective of *changes* in the magnitude and location of *connected loads* and *generating units*.

(b) The *NSP* must ensure that system performance parameter measurements to ensure that the *power system* complies with the performance standards specified in clauses 2.2.1 to 2.2.5 are taken as specified in Table ~~2.8~~ 2.9. Records of all test results must be retained by the *NSP* and made available to the *ISO* on request.

Table ~~2.8~~ 2.9 – Power Quality Parameters Measurement

Parameter	Value measured	*Frequency* of measurement	Minimum measurement period	Data sampling interval
Fundamental *Frequency*	Mean value over interval	Continuous	all the time	10 seconds
Power *frequency voltage* magnitude	Mean RMS value over interval	In response to a complaint, or otherwise as required by the *NSP*.	one week	10 minutes
Short-term flicker severity	P_{st}	In response to a complaint, or otherwise as required by the *NSP*.	one week	10 minutes
Long-term flicker severity	P_{lt}	In response to a complaint, or otherwise as required by the *NSP*.	one week	2 hours
Harmonic / inter-harmonic *voltage* and *voltage* THD	Mean RMS value over interval	In response to a complaint, or otherwise as required by the *NSP*.	one week	10 minutes
Negative sequence *voltage*	Mean RMS value over interval	In response to a complaint, or otherwise as required by the *NSP*.	one week	10 minutes

…

2.4 Under-frequency load shedding and islanding facilities

2.4.1 Under-frequency load shedding schemes

(a) The settings for the under *frequency load shedding* (UFLS) scheme are stated in Table ~~2.9~~ 2.10.

(b) Switchable *capacitor banks* at *substations* must be shed in accordance with Table ~~2.9~~ 2.10.

Table ~~2.9~~ 2.10 – Under-frequency load shedding scheme settings

Stage	*Frequency* (Hz)	Time Delay (sec)	*Stage*	*Load* Shed (%)	Capacitor shed (%)
1	49.00	0.5	UFLS Stage 1	17	35
2	48.75	0.5	UFLS Stage 2	17	
3	48.25	0.5	UFLS Stage 3	17	25

Stage	*Frequency* (Hz)	Time Delay (sec)	*Stage*	*Load* Shed (%)	Capacitor shed (%)
4	48.00	0.5	UFLS Stage 4	17	

2.4.2 Under-frequency islanding schemes

(a) The settings for the *Under Frequency Islanding Scheme (UFIS)* are stated in Table ~~2.9A~~ 2.10A.

Table ~~2.9A~~ 2.10A – Under-frequency load shedding scheme settings

Stage	*Frequency* (Hz)	Time Delay (sec)	*Stage*	Description
1	48.75	0.5	UFIS Stage 1	Separation of Rio Tinto and Horizon Power Networks at Dampier and Cape Lambert
2	48.50	0.5	UFIS Stage 2	Separation of the network between Cape Lambert and South Hedland Terminal

…

2.6.4 Maximum total fault clearance times

(a) This clause 2.6.4 applies to zero impedance short circuit faults of any type on *primary equipment* at nominal system *voltage*. Where *critical fault clearance times* exist, these times may be lower and take precedence over the times stated in this clause 2.6.4. *Critical fault clearance time* requirements are set out in clause 2.6.5.

(b) For *primary equipment* operating at *transmission system voltages*, the maximum *total fault clearance times* in Table ~~2.10~~ 2.11 and Table ~~2.11~~ 2.12 apply to the nominal *voltage* of the circuit breaker that clears a particular fault contribution for both minimum and *maximum system conditions*. For *primary equipment* operating at *distribution system voltages*, the maximum *total fault clearance times* specified for 33 kV and below may be applied to all circuit breakers required to clear a fault for *maximum system conditions*, irrespective of the nominal *voltage* of a circuit breaker.

(c) For *primary equipment* operating at a nominal *voltage* of 220 kV, operation of either *protection scheme* of the *main protection system* must achieve a *total fault clearance time* no greater than the "No CB Fail" time given in Table ~~2.10~~ 2.11. Operation of either *protection scheme* of the *back-up protection system* must achieve a *total fault clearance time* no greater than the "CB Fail" time given in Table ~~2.10~~ 2.11.

(d) For *primary equipment* operating at 132 kV and 66 kV:

(1) one of the *protection schemes* of the *main protection system* must operate to achieve a *total fault clearance time* no greater than the "No CB Fail" time given in Table ~~2.10~~ 2.11. The other *protection scheme* of the *main protection system* must operate to achieve a *total fault clearance time* no greater than the "No CB Fail" time in Table ~~2.11~~ 2.12. The backup *protection system* must achieve a *total fault clearance time* no greater than the "CB Fail" time in Table ~~2.10~~2.11, except that the second *protection scheme* that protects against *small zone faults* must achieve a *total fault* clearance *time* no greater than 400 ms;

(2) on 132 kV lines longer than 40 km, all main and back-up *protection schemes* must operate to achieve the relevant maximum *total fault clearance time* given in Table ~~2.11~~ 2.12; and

(3) on 66 kV lines longer than 40 km, one *protection scheme* of the *main protection system* must operate to achieve the *total fault clearance times* specified for 132 kV in Table ~~2.11~~ 2.12 (rather than the times specified in Table ~~2.10~~ 2.11). The other *protection scheme* of the *main protection system* must operate to achieve the maximum *total fault clearance times* specified for 66 kV in Table ~~2.11~~ 2.12.

(e) For a small zone fault coupled with a circuit breaker failure, maximum total fault clearance times are not defined.

(f) In Table ~~2.10~~ 2.11 and Table ~~2.11~~ 2.12, for *voltages* of 66 kV and above, the term "local end" refers to the circuit breaker(s) of a *protection system* where the fault is located:

(1) within the same *substation* as the circuit breaker;

(2) for a *transmission line* between two *substations*, at or within 50% of the line impedance nearest to the *substation* containing the circuit breaker, provided that the line is terminated at that *substation*;

(3) for a *transmission line* between more than two *substations*, on the same line section as the *substation* containing the circuit breaker, provided that the line is terminated at that *substation*

(g) In ~~2.10~~ 2.11 and Table ~~2.11~~ 2.12, for *voltages* of 66 kV and above, the term "remote end" refers to all circuit breakers required to clear a fault, apart from those specified in clause 2.6.4(f).

{Note: Where one or more circuit breakers required to clear a fault are located in a different *substation* from that at which a line is terminated, situations may arise where all circuit breakers required to clear a fault may operate within the remote end *total fault clearance time*.}

(h) In Table ~~2.10~~ 2.11, for *primary equipment* operating at nominal *voltages* of 33 kV and below, the term "local end" refers to the circuit breaker(s) of a *protection system* where the fault is located:

within the same *substation* as the circuit breaker;

for a line between two substations, at or within 50% of the line impedance nearest to the substation containing the circuit breaker, provided that the line is terminated at that substation;

for a line between more than two substations, on the same line section as the substation containing the circuit breaker, provided that the line is terminated at that *substation*

(i) In Table ~~2.10~~ 2.11, for a line operating at nominal *voltages* of 33 kV and below, the term "remote end" refers to all circuit breakers required to clear a fault, apart from those specified in clause 2.6.4(h).

Table ~~2.10~~ 2.11 – Maximum total fault clearance times (ms)

		New *Equipment* No CB Fail	**New *Equipment* CB Fail**
220 kV	Local end	120	430
	Remote end	140	430
132 kV	Local End	120	430
	Remote end	140	430
66 kV	Local End	120	430
	Remote end	140	430
33 kV HP-Rio tie lines	Local End	105	Not specified
	Remote End	105	Not specified
33 kV and below	Local End	300	Not specified
	Remote End	300	Not specified

Table ~~2.11~~ 2.12 – Alternative Maximum total fault clearance times (ms)

		New *Equipment* No CB Fail	**New *Equipment* CB Fail**
132 kV	Local end	120	270
	Remote end	400	565
66 kV	Local end	105	270
	Remote end	400	565

2.6.5 Critical fault clearance times

(a) Notwithstanding the requirements of clause 2.6.4, where necessary to ensure that the *power system* complies with the performance standards specified in clause 2.2, the *NSP* may, and if directed by the ISO must, designate a part of the *network* as subject to a *critical fault clearance time*. The *critical fault clearance time* may be lower than the standard maximum *total fault clearance time* set out in Table ~~2.10~~ 2.11. The *critical fault clearance time* and the *network* configurations to which it applies shall be specified by the *NSP* and notified to the *ISO*.

…

3.3.1 General

(a) A *generator* must comply at all times with applicable requirements and conditions of connection for *generating units* as set out in this clause.

(b) A *generator* must operate facilities and *equipment* in accordance with any and all *directions* given by the *NSP* under these *Rules* or under any *written law*. For a *covered network,* the *NSP* must not give a direction in excess of what is reasonably necessary in accordance with GEIP.

(c) For *generating units* the combined rating of which is less than 10 MW and which is *connected* to the *distribution system*, the connection requirements of clause 3.4 or clause 3.5 apply. This clause 3.3 applies to *generating units* the combined rating of which is 10 MW or greater.

{NOTE: The 10 MW threshold, is chosen due to the need to treat higher capacity *generators* separately as to their requirements with respect to this clause"

(d) ~~EEA~~ All *generating units* must have *equipment* characteristics and *control systems*, including the inertia (effective, presented to the *power system*), short-circuit ratio and *power system* stabilisers, sufficient not to cause any reduction of *power transfer capability* because of:

(1) reduced ~~rotor angle stability~~ transient and oscillatory stability;

(2) reduced *frequency stability*; or

(3) reduced *voltage stability,* relative to the level that would apply if the *generating unit* were not *connected.*

{Note: The effect of this clause is to prevent *generating units* being permitted to connect to the *network* if, as a result of the connection of the *generator* in accordance with the relevant *access contract* and any *constraint rules* the power transfer capability of the *power system* will be reduced.}

(e) An unplanned trip of a *generating unit* must not cause an increased need for *load shedding* (other than any load which may be shed as a result of inter-trip arrangements in the *generator's* own *access contract* or under a *constraint rule*) because of:

(1) rate of change of frequency;

(2) magnitude of *frequency* excursion;

(3) *active power* imbalance;

(4) *reactive power* imbalance; or

(5) displacement of reactive capability,

over and above the level that would apply if the *generating unit* was not *connected*.

{Note: The effect of this clause is to limit the maximum *generating unit* size that is permitted to connect to the *network* without taking appropriate action to rectify the potential problem or agree suitable terms for constrained access.}

(f) A *generator* must ensure that its transients do not adversely affect the *NSP* and other controllers.

(g) Unless otherwise specified in these *Rules*, the technical requirements for *generating units* apply at the *connection point*.

(h) A *generating unit* must *disconnect* from the *distribution system* if the *distribution feeder* to which it is *connected* is separated from the remainder of the *power system*.

(i) All *generating systems* must ensure that their *connection* to the *power system* does not degrade *power system* damping.

…

3.3.3.3 Generating unit response to disturbances in the power system

…

(f) **Post-fault reactive power of a power station with non-synchronous generating units**

~~After fault clearing, the power station in which a non-synchronous generating unit is located must not absorb reactive power from the transmission system or the distribution system. Any pre-fault absorption of reactive power has to be terminated within 200 ms after clearing of the fault. The absorption is permitted to recommence, if required by the applicable voltage control strategy, after the postfault voltages stabilise for at least 60 seconds at an above nominal value.~~ The *facility* will provide *reactive power* according to its *voltage* droop control and fault-ride through characteristics to maintain voltage at the *connection point* within the *technical envelope*, except where the *facility* is subjected to off-nominal *frequency* and *voltage* excursions beyond the requirements for continuous uninterrupted operation.

{Note: This requirement is intended for under-*voltage* situations where a *generator* is potentially exacerbating the problem.}

(g) **Post fault voltage control of a connection point**

Each *generating unit* must be fitted with an *active power* output *controller*, such as a governor, and a *voltage* regulator so that, following the occurrence of any *credible contingency event* and *changed power system* conditions after *disconnection* of the faulted element, the *generating unit* must be capable of delivering to the *network active power* and *reactive power*

sufficient to ensure that the *connection point voltage* is within the range for continuous uninterrupted operation for that *generating unit*.

…

Schedule 10: Frequency control dead band [Issue 18]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 18' in the HTR workbook. An issue paper was presented on 14 November 2024.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

A definition of 'frequency dead band' is added to clause 1.5.

Clause 3.3.4.4 requires generating systems to maintain a 0.05 Hz dead band, within which they provide no frequency response. The point at which the dead band is measured in the current drafting needs to be clarified and updated. Clarification is provided to specify that the 0.05 Hz dead band is applied ±0.025 Hz around 50 Hz.

1.5 Interpretation

…

frequency	for alternating current electricity — means the number of cycles occurring in each second, measured in Hz.
frequency dead band	means the range of *power system* frequency for which a change in a *generating unit*'s *active power* output in response to *power system frequency* is not required
frequency operating standards	means the standards which specify the *frequency* levels for the operation of the *power system* set out in clause 2.2.

…

3.3.4.4 Frequency control

…

(d) **Dead Band**

~~The dead band of a *generating unit* (the sum of increase and decrease in *power system frequency* before a measurable *change* in the *generating unit*'s *active power* output occurs) must be less than 0.05 Hz, unless an adjustable dead band is agreed to in the *access contract*.~~ The *frequency dead band* of a *generating unit* must be less than or equal to ±0.025 Hz around 50 Hz.

…

Schedule 11: Disturbance monitoring and synchrophasors [Issues 22 and I2025.06]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 22' and 'Issue I2025.06' in the HTR workbook. An issue paper for Issue 22 was presented on 14 November 2024 and Issue I2025.06 on 7 August 2025. Further drafting instructions were provided by the Issue Lead on 14 October 2025 and 6 November 2025. Issue I2025.06 was discussed at the 7 August 2025 meeting and agreed to progress to Rule Drafting. Further drafting instructions were provided on 20 August 2025 and 14 October 2025.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

A new definition of remote monitoring equipment has been introduced to clause 8 of the PNR.

Rule 141 of the PNR is amended to change the name of the current Metering Procedure into the Metering and Measurements Procedure.

New rules 148A and 148B have been included which require the ISO to provide specifications for data formats and data exchange protocols of all power system measurements it requires to perform its functions under the Rules, as well as outline the methods of cost recovery for the installation of new measurement equipment.

A definition of 'high-resolution data' and 'high resolution data recorder' has been introduced to clause 1.5 of the HTR, and the definition of 'point of common coupling' has been amended to apply to all NSPs, not just Horizon Power.

Clauses 3.3.4.1(c) and 3.6.10.1(b) of the HTR have been amended to align with the changes to the Metering and Measurements Procedure (new rule 148A of the PNR).

New clause 3.3.4.6 has been added, outlining that an NSP may require a controller to install maintain, upgrade, modify or replace high resolution data recorders, the circumstances under which the ISO may request for high resolution data recorders to be installed, and the type of data that high-resolution data recorders must provide.

Pilbara Networks Rules

Subchapter 1.2 – Interpretation

{A word or phrase defined in the Act or the Regulations has the same meaning when used in these Rules.}

8 Glossary

(1) A word or phrase defined below has the meaning given —

…

Reliability {also "**reliable**"}: Means a measure of a Power System's ability to deliver electricity to all points of consumption and receive electricity from all points of supply within accepted standards and in the amount desired.

{***Reliability*** is best considered as an outcome, from a Power System having both **Security** and adequacy, where "adequacy" in turn consists of both generation adequacy and Network adequacy.}.

Remote Monitoring Equipment: Means Equipment installed to enable the monitoring of other Equipment from a remote control centre and includes a remote terminal unit (RTU).

Representative: In relation to a person, means the person's representative, including an employee, agent, officer, director, auditor, adviser, partner, consultant, joint venturer or sub-contractor, of that person.

…

141 Metering Procedure

(1) The ISO ~~may Develop~~ must Develop a Procedure ("**~~Metering Procedure~~ Metering and Measurements Procedure**") governing the gathering, storage, updating and communication to it and other persons of metering and other data under this Chapter 5.

(2) ~~The Metering~~ and Measurements ~~Procedure must, so far as practicable consistent with meeting the requirements of these Rules, seek to minimise compliance costs.~~ In developing the Metering and Measurements Procedure, the ISO must consider and, so far as is practicable, seek to minimise compliance costs.

(3) The ISO must have regard to rule 5 when Developing the Metering and Measurements Procedure.

…

148 Covered NSP must provide information

The ISO may request, and a Covered NSP must provide, any information relating to the methodologies, models, software, data sources and internal Procedures used by the NSP for Loss Factor calculation and determination.

Subchapter 5.3 – Power System Measurements

148A Collection of power system data by the ISO

(1) The ISO, in consultation with registered NSPs, must –

(a) develop specifications for data formats and data exchange protocols for all power system measurements, other than metering data, that may be collected by the ISO or the ISO Control Desk to facilitate their functions under these Rules, including:

(i) to manage the Visibility regime under Subchapter 4.3;

(ii) to create, Maintain, manage and operate the Power System Model under Subchapter 4.4;

(iii) to undertake Loss Factors functions under Subchapter 5.2.

(iv) through the ISO Control Desk, to participate in system operations activities under Subchapter 7.5;

(v) to undertake post-incident discussion and investigations under Subchapter 7.6;

(vi) to procure Essential System Services under Subchapter 8.1; and

(vii) to develop and administer Constraint Rules under Subchapter 9.1; and

(b) develop processes for:

(i) identifying locations and criteria requiring new or improved Remote Monitoring Equipment and high-resolution data recorders as defined in the HTR;

(ii) implementing new or improved Remote Monitoring Equipment and high-resolution data recorders; and

(iii) identifying circumstances when data and measurements defined in the HTR are not required or may be inferred via means other than installation of Remote Monitoring Equipment or high resolution data recorders.

(2) The ISO and registered NSPs have discretion to determine what data formats and data exchange protocols are included in the Metering and Measurements Procedure to facilitate the ISO or the ISO Control Desk functions under these Rules.

(3) Any specifications for data formats, high resolution data recorders or data exchange protocols developed by the ISO must be detailed in the Metering and Measurements Procedure defined in Rule 141.

148B Cost recovery to install measurement equipment

Subject to the Access Code, the costs a controller incurs while installing new or upgraded equipment required under these Rules to collect power system data may recovered from the NSP in accordance with the terms of the relevant access contract, or otherwise by agreement between the NSP and the Controller.

{Note — the cost recovery specified in this Rule may be the subject of a rule dispute}

…

Harmonised Technical Rules

1.5 Interpretation

…

halving time	means the elapsed time required for the magnitude of a damped sine wave to reach half its initial value.
high resolution data	means data measured and transmitted to the *ISO* in near real time by devices with GPS clock synchronisation (or equivalent technology) and a typical reporting interval of 20 milliseconds, allowing for accurate representation of power system behaviour, including during transient events, including: - Measurement of *power system frequency* and electrical time; and - Data measured by phasor measurement units and other devices that is transmitted for real time operational purposes.

high resolution data recorder	means a device (such as a phasor measurement unit or other type of device specified under the *Pilbara networks rules* from time to time) that produces High Resolution Data in accordance with the applicable requirements of the *Pilbara networks rules*.
high voltage	means any nominal *voltage* at or above 35 kV

…

point of common coupling	means the point on the *network* at which ~~Horizon Power~~ the *NSP* requires compliance with the Technical Rules clauses 2.3.3(a) and 2.3.4(a). Under normal circumstances this compliance is required at the connection point, but ~~Horizon Power~~ the *NSP* may, at its sole discretion, allow the "point of common coupling" to be at a point on the network upstream from the connection point, where it is reasonable to do so in accordance with good electricity industry practice.

…

3.3.4.1 Remote monitoring

…

(c) Any RME or provided, upgraded, modified or replaced (as applicable) under clause 3.3.4.1 and, must conform to an acceptable standard as agreed between the *NSP* and the *controller* and must be compatible with the *NSP's SCADA system* and the specifications for data formats and data exchange protocols outlined in the *ISO's* Metering and Measurements Procedure.

…

3.3.4.6 High resolution data recorders

(a) *Controllers* must install and maintain *high resolution data recorders* in accordance with rule 148A, with costs recovered in accordance with rule 148B of the *Pilbara networks rules*.

(b) An *NSP* may require a *controller* of an existing *power station* to:

(1) install, upgrade and maintain *high resolution data recorders* to enable the *NSP* to monitor performance of a *generating unit* or connection point connected to its *network* (including its dynamic performance) where access to high resolution measurement data is necessary to facilitate the *NSP's* or *ISO's* functions under these *Rules*; or

(2) upgrade, modify or replace any *high resolution data recorders* already installed in a *power station* connected to the *NSP's network* if they no longer comply with the requirements of the *Pilbara networks rules* and *GEIP*, and notice is given in writing to the relevant *generator* accordingly.

(c) Information to be measured by *high resolution data recorders* may include the current (A or kA), *voltage* (V or kV) and *frequency* (Hz) at the *generating unit* or *connection point*; and

(d) *High resolution data recorders*, using the metrics in clause 3.3.4.6(c), must be able to calculate the transient and disturbance response of each *generating unit* or *connection point* in terms of real and *reactive power* output (MW and MVAr).

(e) The *ISO* may, after consultation with the relevant *NSP*, request the *NSP* to issue and implement a notice to a *controller* under clause 3.3.4.6(b), if the *ISO* considers that:

(1) the provision of particular *high resolution data recorders* is necessary to maintain or improve *power system security*; and

(2) the *NSP* is not adequately managing the need for the *high resolution data recorders*.

(f) The *ISO* notice provided to an *NSP* or *controller* under clause 3.3.4.6(e) must clearly specify the circumstances in which the data is required, the implications for *power system security* (including the relevant rule provisions relied upon by the *ISO*), and identify any events or conditions that led to the *ISO*'s decision.

…

3.6.10.1 Remote monitoring

…

(b) An *RME* provided, upgraded, modified or replaced (as applicable) in accordance with subclause 3.6.10.1(a) must conform to an acceptable standard as agreed by the *NSP* and must be compatible with the *NSP's SCADA system*, including the requirements of clause 5.10, and the specifications for data formats and data exchange protocols outlined in the *ISO's* Metering and Measurements Procedure.

…

Schedule 12: Changes to Figure 3.3 [Issue 23] and to the reactive power capability of inverter-based generating units, to ensure HTR requirements are technology agnostic [Issue I2025.2]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 23 and Issue I2025.02' in the HTR workbook. An issue paper for Issue 23 was presented on 14 November 2024 and a paper for Issue I2025.02 was presented on 9 October 2025. Further drafting instructions were provided on 18 September 2025 and 6 November 2025. In addition, input was sought from the wider Working Group on 22 October 2025.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026

Clauses 3.3.3.1(c)(1) – (5), Clause 3.3.3.1(d) and Figures 3.1, 3.2 and 3.3 have been amended to create a standardized, technology agnostic approach to the reactive power capabilities of generating units, as well as cater for the ability of storage works to absorb reactive power.

Clause 3.3.3.1(i) grandfathers these amendments to the time an access contract was executed.

Clauses 3.3.3.3(b), 3.3.3.3(c)(2), 3.3.3.3(e), 3.3.3.8(b)(2), Note 1 to Figure 3.4 and Figures 3.4, 3.5 and 3.6 have been amended to align with the changes to 3.3.3.1(c).

3.3.3.1 Reactive power capability

…

(c) Therefore:

~~(1) Each *synchronous generating unit*, while operating at any level of *active power* output between its maximum and minimum *active power* output level as notified to the *NSP*, must be capable of:~~

~~*(A) supplying* at its *generator machine's* terminals an amount of *reactive power* of at least the amount equal to the product of the rated *active power* output of the *generating unit* at nominal *voltage* and 0.750; and~~

~~*(B)* absorbing at its *generator machine's* terminals an amount of *reactive power* of at least the amount equal to the product of the rated *active power* output of the *generating unit* at nominal *voltage* and 0.484.~~

(1) Each *generating unit* must be capable of *supplying* or absorbing *reactive power* continuously of at least the amount equal to the product of the notified maximum *active power* output of the *generating unit* at nominal voltage and 0.484 while operating at any level of *active power* output between its maximum *active power* output and its notified minimum *active power* absorption level.

Refer to Figure 3.1 for details.

{Note: This clause requires a *generator machine*, when producing its notified maximum *active power* output, to be capable of operating at any *power factor* between ~~0.8~~ 0.9 lagging and 0.9 leading.}

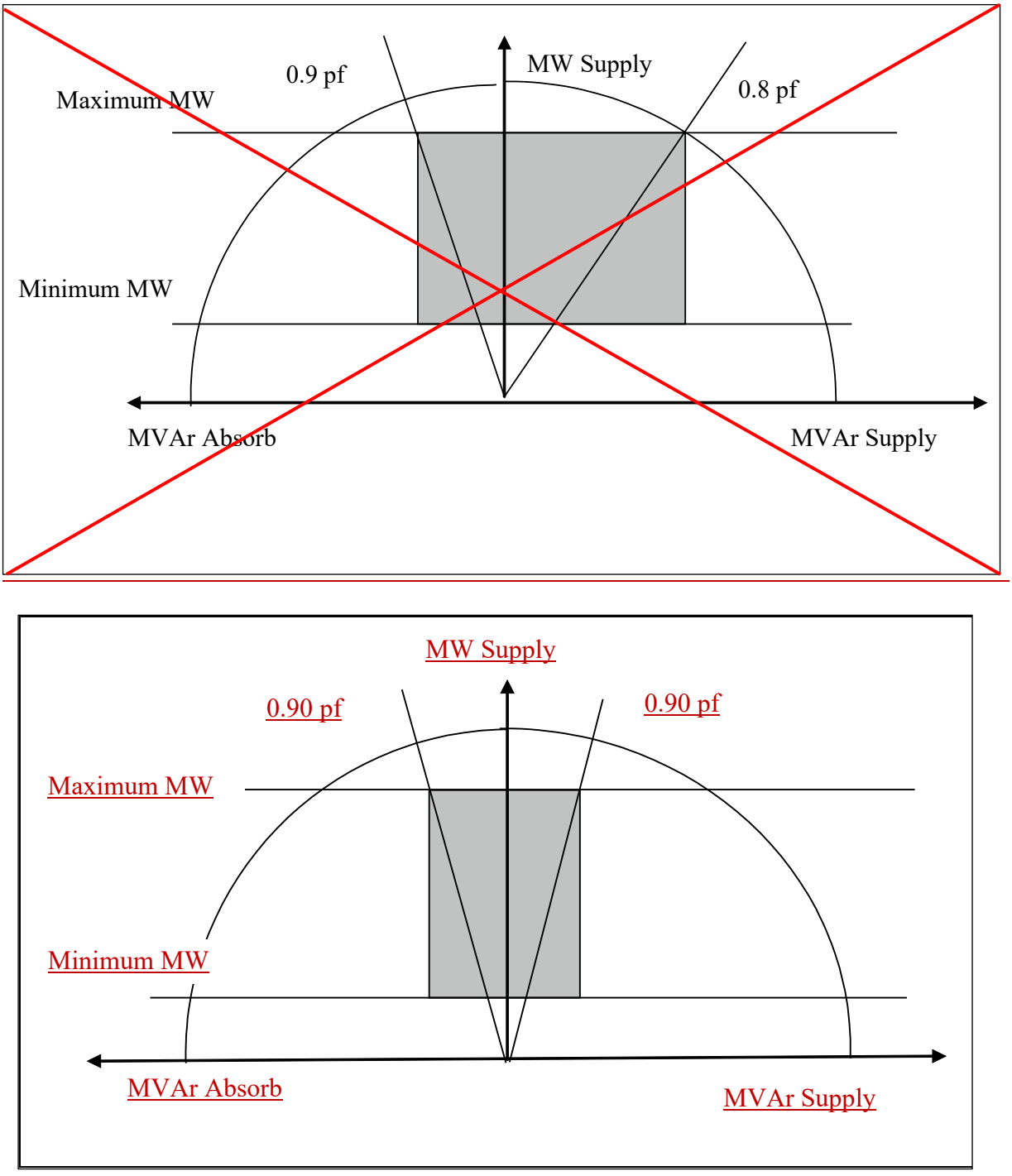
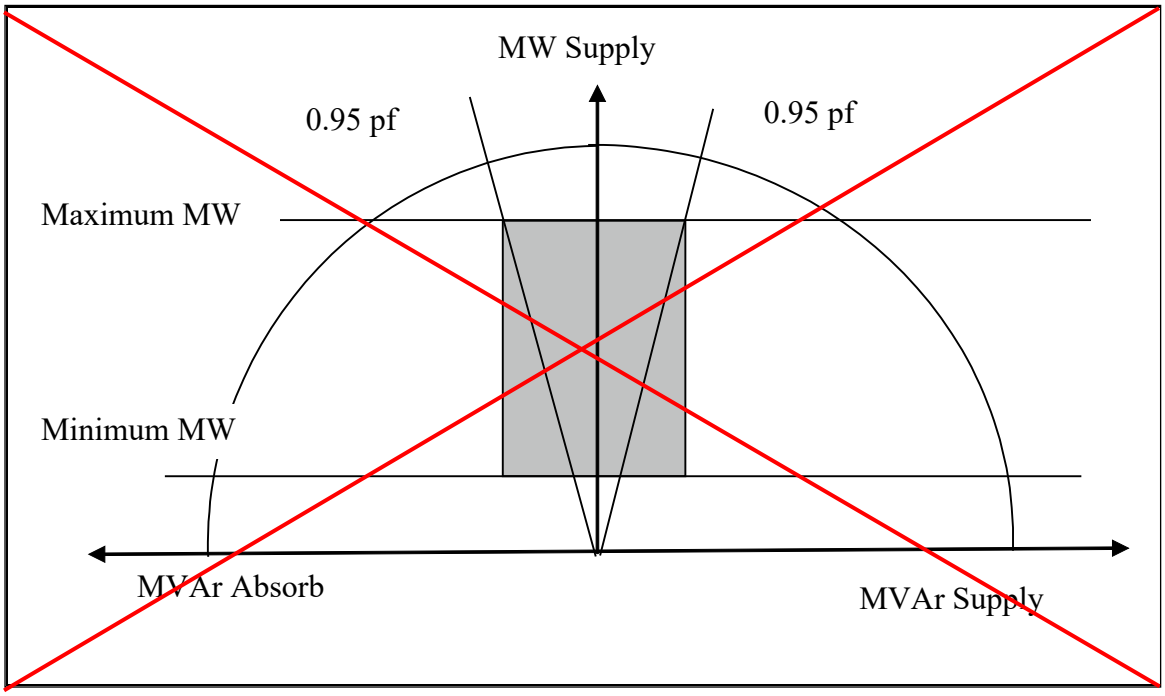


Figure 3.1 – ~~Synchronous g~~ Generating unit. Minimum reactive power capability requirements at generator machine terminals shown shaded

~~(2) Each induction generating unit, while operating at any level of active power output between its notified maximum and minimum output level, must be capable of supplying or absorbing an amount of reactive power at the connection point of at least the amount equal to the product of the rated active power output of the generating unit at nominal voltage and 0.329. Refer to Figure 3.2 for details.~~

~~{Note: This clause requires an induction generating unit, when producing its notified maximum active power output, to be capable of operating at any power factor between 0.95 lagging and 0.95 leading.}~~

~~(3) Where necessary to meet the performance standards specified in clause 2.2, the NSP and the generator may agree that an induction generating unit is to be capable of supplying or absorbing a greater amount of reactive power output than specified in subclause 3.3.3.1(c)(2). The need for such a requirement will be determined by power system simulation studies and any such a requirement must be included in the access contract.~~

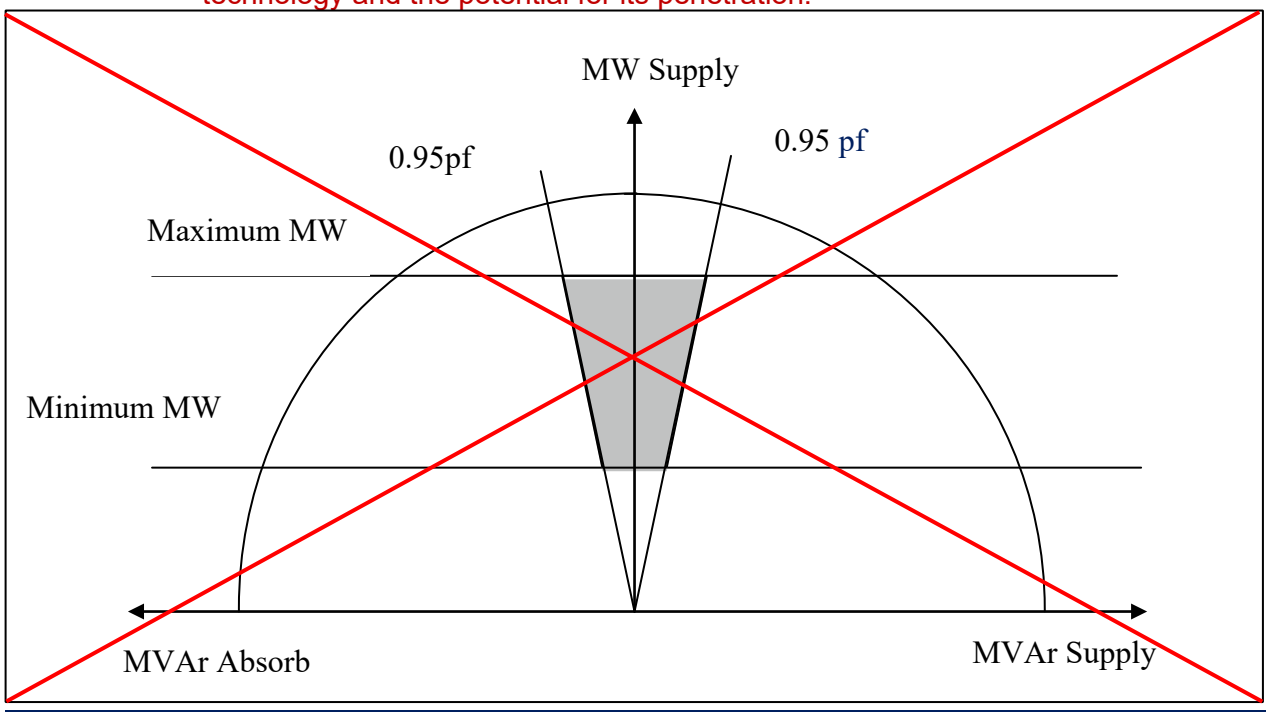


~~Figure 3.2 – Induction generating unit. Minimum reactive capability requirements at connection point shown shaded~~

~~(4) Each inverter coupled generating unit or converter coupled generating unit, while operating at any level of active power output between its notified maximum and minimum output level, must be capable of supplying reactive power such that at the inverter or converter connection point the lagging power factor is less than or equal to 0.95 and must be capable of absorbing reactive power at a leading power factor less than or equal to 0.95. Refer to Figure 3.3 for details.~~

~~(5) Where necessary to meet the requirements of these *Rules*, the *NSP* and the *generator* may agree that an inverter *generating unit* is to be capable of *supplying* a *reactive power* output coincident with rated *active power* output over a larger *power factor* range. The need for such a requirement be determined by *power system* simulation studies and any such a requirement must be included in the *access contract*.~~

~~(d) For *generating units* not described by subclause 3.3.3.1(c), the *power factor* requirements must be as agreed between the *NSP* and the *generator* and included in the *access contract*. In determining the appropriate *power factor* requirement, the *NSP* and *generator* and, if applicable, the *ISO* must consider the intrinsic capabilities of such a new technology and the potential for its penetration.~~



~~Figure 3.3 – Inverter coupled generating unit or converter coupled generating unit. Minimum reactive capability requirements at connection point shown shaded~~

(2) *Storage works*, while operating at any level of *active power* output between its maximum *active power* output level and maximum loading level, must be capable of supplying and absorbing at its terminals an amount of *reactive power* of at least the amount equal to the product of the rated *active power* output of the *generating unit* at nominal *voltage* and 0.484.

Refer to Figure 3.2.

{Note: This clause requires an inverter connected energy storage device, when producing its notified maximum *active power* output or absorption, to be capable of operating at any *power factor* between 0.9 lagging and 0.9 leading. Refer to Figure 3.2 for details}

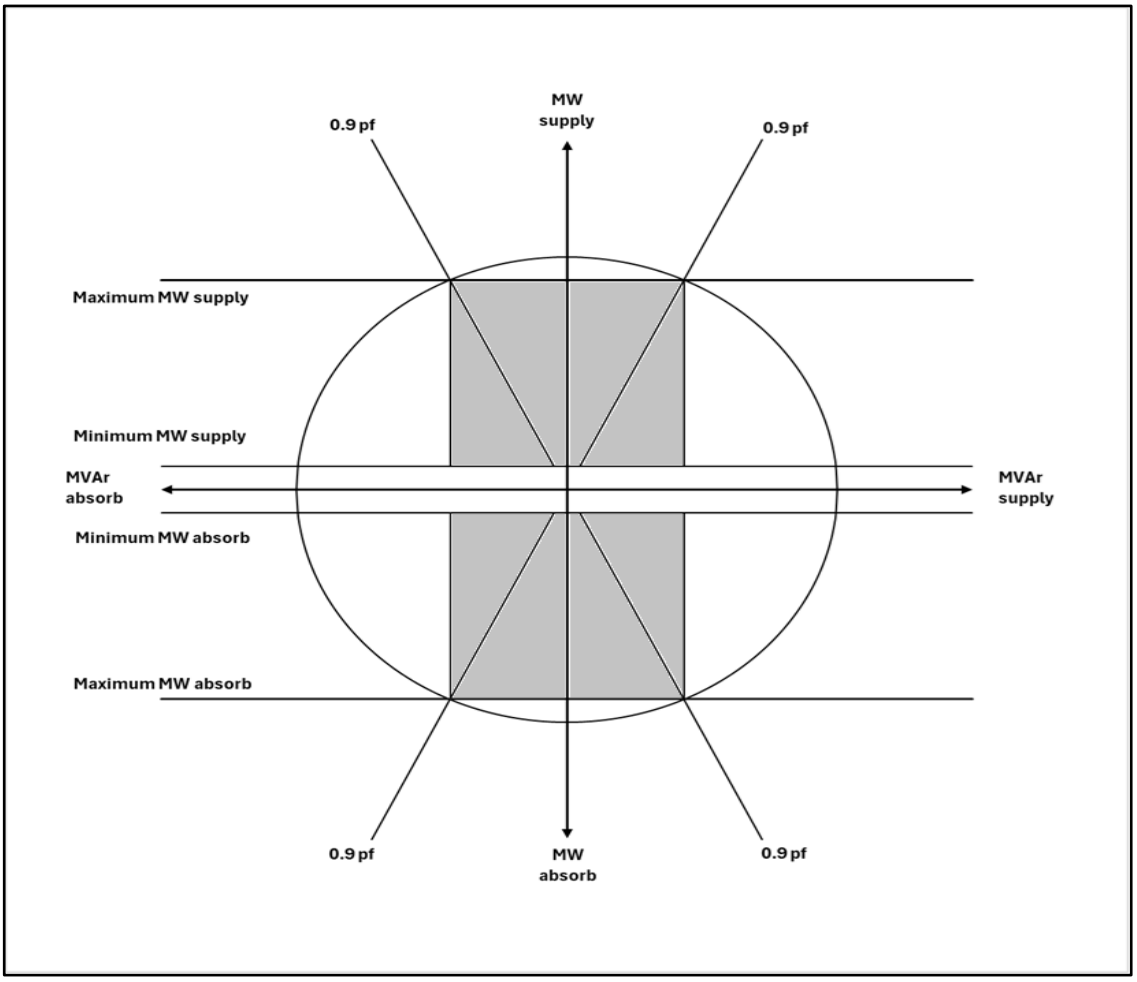


Figure 3.2 – Energy storage device. Minimum reactive power capability shown shaded

(3) Where necessary to meet the performance standards specified in clause 2.2, the *NSP* and the *generator* may agree that a *generating unit* is to be capable of supplying or absorbing a greater amount of *reactive power* output than specified in subclause 3.3.3.1(c)(1) and 3.3.3.1(c)(2). The need for such a requirement will be determined by *power system* simulation studies, and any such requirement must be included in the *access contract*.

(d) For *generating units* not described by subclause 3.3.3.1(c), the *power factor* requirements must be as agreed between the *NSP* and the *generator* and included in the *access contract*. In determining the appropriate *power factor* requirement, the *NSP* and *generator* and, if applicable, the *ISO* must consider the intrinsic capabilities of such a new technology and the potential for its penetration.

(e) If the *power factor* capabilities specified in subclause 3.3.3.1(c) cannot be provided by the *generator machine*, the *generator* must provide the required capacity by including an additional source of *reactive power* within

the *facility*. The *control system* for the additional source of *reactive power* must be coordinated with that of the main *generator* and, together, they must meet the performance requirements of clause 3.3.4.5.

{Note: This subclause 3.3.3.1(e) is intended to facilitate flexibility in design by assisting proponents to connect *generating units* that, of themselves, are not capable of meeting the *reactive power generation* requirements specified in clause 3.3.3.1 through providing for the shortfall to be made up through some other means such as *static VAr compensators*, *static synchronous compensators,* inverters, thyristor switched *capacitor banks* and thyristor switched *reactors.}*

(f) If the *voltage* at the *connection point* falls below the steady state level permitted by clause 2.2.2, the output current of the *facility* must not be less than the output current of the *facility* if it was providing the maximum *reactive power* required by this clause 3.3.3.1 when generating its maximum rated *active power* with the *connection point* at nominal *voltage*.

(g) The *NSP* and *generator* may agree that the *generator* is required to achieve full compliance with the requirements of this clause 3.3.3.1 in return for a capital contribution towards the provision of new sources of *reactive power* within the *transmission* or distribution *network*. The basis for determining the required capital contribution must be the additional capital cost that the proponent would reasonably be expected to incur if full compliance with the requirements of this clause was not waived.

(h) Each *generating unit's* connection must be designed to permit the *dispatch* of the full *active power* and *reactive power capability* of the *facility*.

(i) If the *power factor* capabilities specified in subclause 3.3.3.1(c) are amended at any time, a *generator* may maintain the *power factor* requirements required at the time the relevant *access contract* was executed.

…

3.3.3.3 Generating unit response to disturbances in the power system

…

(b) **Immunity to frequency excursions**

A *generating unit* and a *power station* in which the *generating unit* is located must be capable of continuous uninterrupted operation within the *power system frequency* envelope specified in Figure ~~3.4~~ 3.3. Operation for a period of at least 20 seconds is required each time the *frequency* is below 47.5 Hz. Operation for a period of at least 6 seconds is required each time the *frequency* is above 52 Hz. Below 47 Hz and above 52.5 Hz, instantaneous *disconnection* of *generating units* is permitted.

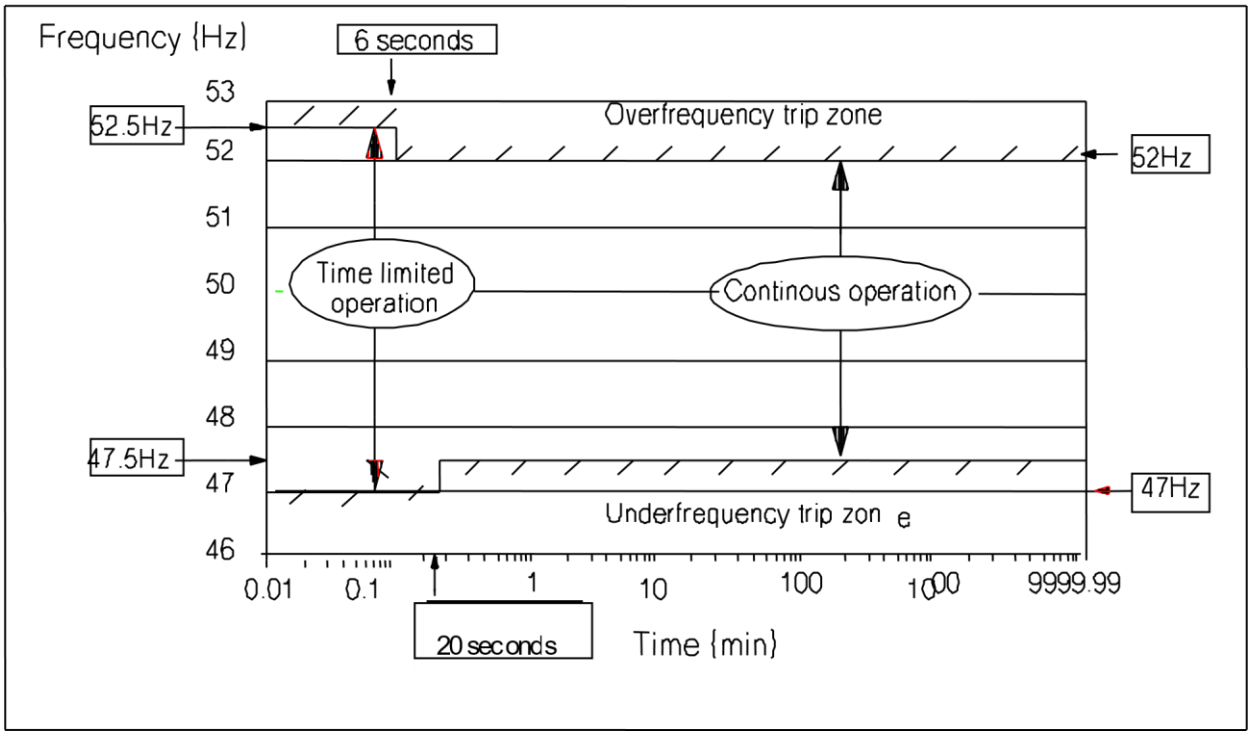


Figure ~~3.4~~ 3.3 – Off nominal frequency operation capability requirement for generating units

{Note:

1. The requirements of Figure ~~3.4~~ 3.3 provide a safety margin relative to the *frequency operating standards* of Table 2.1, within which a *generator* may apply for an exemption from compliance from these *Rules*.

2. These requirements must be met for all operating conditions, including ambient temperature. Unless operating restrictions have been agreed in accordance with subclause 3.1(b) the *NSP* may assume the site specific maximum ambient temperature indicated in subclause 3.3.3.1(a) when assessing compliance with the requirements of this clause.

(c) **Immunity to voltage excursions**

(1) A *generating unit* and the *power station* in which the *generating unit* is located must be capable of continuous uninterrupted operation for *network* faults which cause the *voltage* at the *connection point* to drop below the nominal *voltage* for a period equal to the *circuit breaker failure* fault clearing time to clear the fault plus a safety margin of 30 ms, followed by a period of 10 seconds where the *voltage* may vary in the range 80% to 110% of the nominal *voltage,* and a subsequent return of the *voltage* within the range 90 to 110% of the nominal *voltage.*

(2) Notwithstanding the requirements of subclause 3.3.3.3(c)(1) no *generating unit* shall be required to be capable of continuous uninterrupted operation where the *voltage* at the *connection point* falls below the envelope shown in Figure ~~3.5~~ 3.4.

Nominal *Voltage*

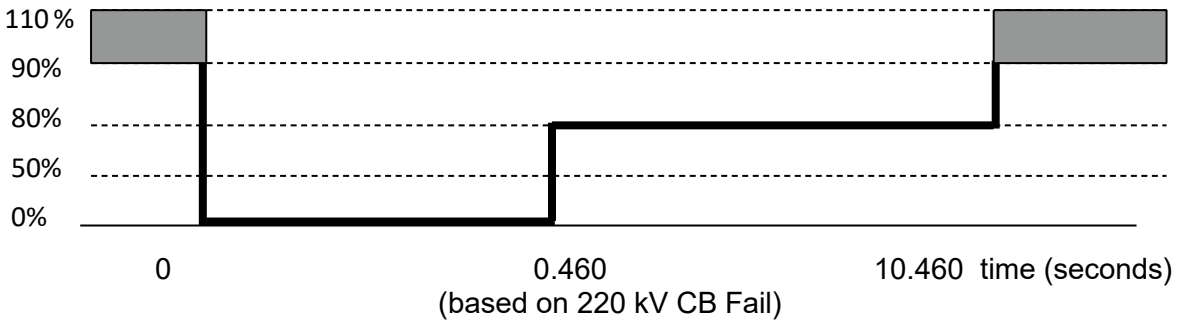


Figure ~~3.5~~ 3.4 – Off nominal *voltage* operation capability requirement for *generating units*.

(d) **Immunity to rate-of-change of frequency**

A *generating unit* and the *power station* in which the *generating unit* is located must be capable of continuous uninterrupted operation for any rate-of-*change*-of-*frequency* of up to 4 Hz per second.

(e) **Immunity to high speed auto reclosing**

A *generating unit* and the *power station* in which the *generating unit* is located must be capable of continuous uninterrupted operation for *voltage* transients caused by high speed auto-reclosing of *transmission lines* irrespective of whether or not a fault is cleared during a reclosing sequence. See Figure ~~3.6~~ 3.5 for details of the *low voltage* ride through requirement during auto-reclose operation.

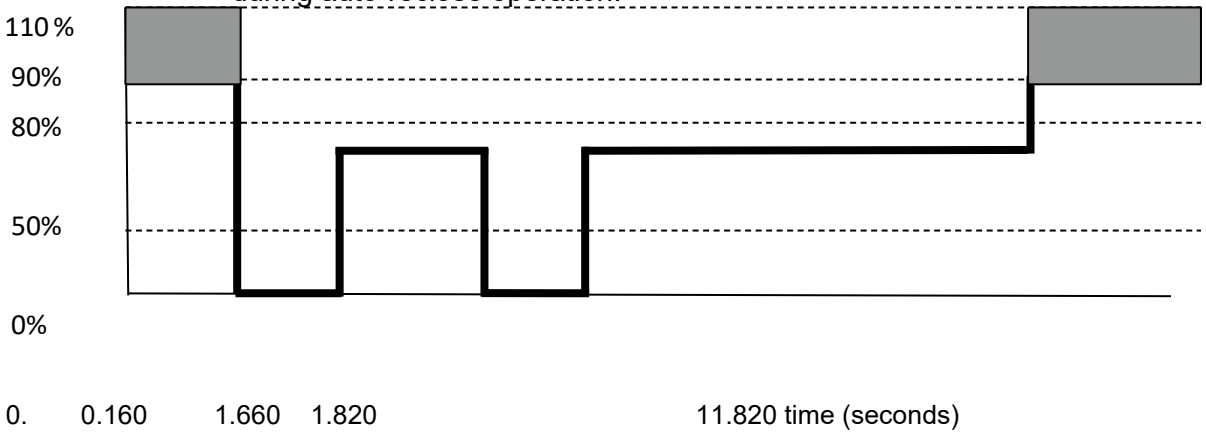


Figure ~~3.6~~ 3.5 – Off nominal *voltage* operation capability requirement for *generating units* during auto-reclose operation

…

3.3.3.8 Protection of generating units from power system disturbances

…

(b) The abnormal conditions referred to in clause 3.3.3.8(a) are to be agreed between the *generator* and the *NSP*, and may include:

(1) loss of synchronism;

(2) high or low *frequency* outside the *generator* off-nominal *frequency* operation capability requirements specified in Figure ~~3.4~~ 3.3;

…

Schedule 13: Treatment of Ambient Temperatures [Issue 24]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 24' in the HTR Workbook. An issue paper was presented on 14 November 2024. Further clarification was received from the Issue Lead on 18 September 2025.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

These changes clarify the treatment of ambient temperatures in the HTR. They also clarify the distinction of using 'nameplate' versus a derated capacity when determining which set of generator compliance rules should apply.

Clauses 3.3, 3.4, 3.5 and the notes to Table 3.1 are amended to clarify that for the purposes of generator classes and technical requirements, the nameplate capacity of a generating unit or an item of equipment, shall be used.

The notes following clause 3.3.3.1(a) and the fifth note to Table 3.1 are amended to are amended to clarify that site specific maximum ambient temperature is determined by the NSP with a 1% probability of exceedance, or 50 degrees Celsius when assessing compliance with the requirements of clause 3.3.3.1(a).

The removal of 'distribution network' from the title of section 3.4 clarifies that the requirements for connection of small generating units up to 10MW is applicable on both transmission and distribution networks.

3.3 Requirements for connection of generating units > 10 MW

(a) For the purposes of *generator* classes and technical requirements, the *nameplate rating* of a *generating unit* or an item of *equipment* must be used.

3.3.3.1 Reactive power capability

(a) Each *generating unit*, and the *power station* in which the *generating unit* is located, must be capable of continuously providing its full *reactive power* output required under this clause within the full range of steady state *voltages* at the *connection point* permitted under clause 2.2.2. This requirement must be met for all operating conditions, including ambient temperature.

{Notes Unless operating restrictions have been agreed in accordance with subclause 3.1(b), the *NSP* may assume the site specific maximum ambient temperature as determined by the *NSP* with a 1% probability of exceedance, or 50 degrees Celsius, when assessing compliance with the requirements of clause 3.3.3.1(a).}

…

Table 3.1 – Synchronous generator excitation control system performance requirements

Performance Item	Units	Static Excitation	AC Exciter or Rotating Rectifier	Notes
***Sensitivity*:** A sustained 0.5% error between the *voltage* reference and the sensed *voltage* must produce an excitation *voltage change* of not less than 1.0 per unit.	Open loop gain (ratio)	200 minimum	200 minimum	1, 5
Field *voltage* rise time: Time for field *voltage* to rise from rated *voltage* to excitation ceiling *voltage* following the application of a short duration impulse to the *voltage* reference.	second	0.05 maximum	0.5 maximum	2, 4, 5
Settling time with the *generating unit* unsynchronised following a disturbance equivalent to a 5% step *change* in the sensed *generating unit* terminal *voltage*.	second	1.5 maximum	2.5 maximum	3, 5
Settling time with the *generating unit* synchronised following a disturbance equivalent to a 5% step *change* in the sensed *generating unit* terminal *voltage*. Must be met at all operating points within the *generating unit* capability.	second	2.5 maximum	5 maximum	3, 5
Settling time following any disturbance which causes an excitation limiter to operate.	second	5 maximum	5 maximum	3, 5

{Note:

1. One per unit excitation *voltage* is that field *voltage* required to produce nominal *voltage* on the air gap line of the *generating unit* open circuit characteristic (Refer IEEE Standard 115-1983 - Test Procedures for Synchronous Machines). *Excitation control system* with both proportional and integral actions must achieve a minimum equivalent gain of 200.
2. Rated field *voltage* is that *voltage* required to give nominal *generating unit* terminal *voltage* when the *generating unit* is operating at its maximum continuous rating. Rise time is defined as the time taken for the field *voltage* to rise from 10% to 90% of the increment value.
3. Settling time is defined as the time taken for the *generating unit* terminal *voltage* to settle and stay within an error band of ±10% of its increment value.
4. Field *voltage* means *generating unit* field *voltage*.
5. For the purposes of generator classes and technical requirements, *nameplate rating* for a *generating unit* or an item of *equipment* will be used.}

…

3.4 Requirements for connection of small generating units ~~to the distribution network~~ (1000 kVA up to 10 MW)

(a) For the purposes of generator classes and technical requirements, the *nameplate rating* of a *generating unit* or an item of *equipment* will be used.

…

3.5 Requirements for connection of energy to the low voltage distribution system via inverters (up to 1000 kVA)

…

(d) The *NSP* of a *covered network* must *publish* a copy of its current *procedure*.

{Note: The scope of this clause is limited to technical conditions of connection. The *NSP* is able to enter into an *energy* buyback agreement with a *controller*. It should also be noted that whereas this clause covers *connection* issues for *generators* up to 1000 kVA, the maximum *generator* capacity for which an *NSP* may be prepared to enter into an *energy* buyback agreement may be less than this amount.}

(e) For the purposes of generator classes and technical requirements, the *nameplate rating* of a *generating unit* or an item of *equipment* will be used.

…

Schedule 14: Monitoring and control requirements [Issue 26]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 26' in the HTR Workbook. A drafting proposal was presented to the group in the issues paper of 9 October 2025.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

The Requirements for Monitoring and Control of Equipment framework is primarily based on control technologies for traditional synchronous machines. It also needs to adequately address inverter-based generation technologies. Additionally, it needs to capture the necessary data and control points required for an evolved Pilbara regime.

Existing clause 3.4.9 is amended to extend remote control, monitoring units and communication requirements to all generators, removing the exception for generating units exporting below 1 MW.

Clause 3.5.2(a) is amended to specify remote control, monitoring and communication requirements for inverter coupled generating units (up to 1000KVA).

Clause 3.5.2(b) is included to ensure the requirements in new clause 3.5.2(a) do not apply retrospectively.

Clause 5.9.2 has been amended to remove facsimile numbers from the required forms of operational communications.

3.4.9 Remote control, monitoring and communications

(a) ~~For *generating units* exporting 1 MW or more to the *distribution system* the~~ A *generator* must provide for:

(1) tripping of the *generating unit* remotely from the *NSP's control centre*;

(2) a close-enable interlock operated from the *NSP's control centre*; and

(3) remote monitoring at the *control centre* of (signed) MW, MVAr and *voltage*.

~~(b) For *generating units* exporting less than 1 MW monitoring may not be required. However, where concerns for safety and *reliability* arise that are not adequately addressed by automatic *protection systems* and interlocks, the *NSP* may require the *generator* to provide remote monitoring and remote control of some functions in accordance with subclause 3.4.9(a).~~

~~(c)~~(b) A *generator* must provide a continuous communication link with the *NSP's control centre* for monitoring and control for *generating units* ~~exporting 1 MW and above to the *distribution system*. For *generating units* exporting below 1 MW, non-continuous monitoring and control may be required e.g. a bi-directional dial up arrangement~~.

~~(d)~~(c) A *generator* must have available at all times a telephone link or other communication channel to enable voice communications between a small *power station* and the *NSP's control centre*. ~~For *generating units* exporting above 1 MW, a~~ A back-up speech communications channel pursuant to subclause 3.3.4.3(d) may be required.

…

3.5 Requirements for connection of energy to the low voltage distribution system via inverters (up to 1000 kVA)

3.5.1 General

(a) An *NSP* (after consulting with the *ISO*) must develop and maintain, and may from time to time update, a *procedure* setting out its requirements for the connection of *energy* systems to the *NSP's low voltage distribution system* via inverters. It covers installations rated up to 1000 kVA. For similarly rated non-inverter-*connected energy* systems, the requirements of clause 3.4 apply.

(b) The *procedure* is to be consistent with:

(1) GEIP;

(2) for a covered network, the Pilbara electricity objective;

(3) the objective of maintaining and improving *security.*

(c) The *NSP* must provide a copy of its current *procedure* to the *ISO*.

(d) The *NSP* of a *covered network* must *publish* a copy of its current *procedure*.

{Note: The scope of this clause is limited to technical conditions of connection. The *NSP* is able to enter into an *energy* buyback agreement with a *controller*. It should also be noted that whereas this clause covers *connection* issues for *generators* up to 1000 kVA, the maximum *generator* capacity for which an *NSP* may be prepared to enter into an *energy* buyback agreement may be less than this amount.}

3.5.2 Remote control, monitoring and communications

(a) For *non-synchronous generating units* (up to 1000 kVA) *connected* to the *low voltage distribution* system, a *generator* must provide for:

(1) tripping of the *generating unit* or control of *generating unit* real power output remotely from the *NSP's control centre*; and

(2) remote monitoring at the *control centre* of positive or negative MW, MVAr and *voltage*.

(b) Requirements to install *RCE, RME,* and communications *equipment* to enable remote control, monitoring and communications do not apply to Clause 3.5.2(a) does not apply to *non-synchronous generating units* (up to 1000 kVA) *connected* to the *low voltage distribution* system installed prior to the commencement of clause 3.5.2(a).

…

5.9.2 Power system operational communication facilities

(a) A *controller* must advise the *NSP* of its requirements for the giving and receiving of *operational communications* in relation to each of its facilities. The requirements which must be forwarded to the *NSP* include:

(1) the title of contact position;

(2) the telephone numbers of that position;

(3) the telephone numbers of other available communication systems in relation to the relevant *facility*; and

~~(4) a facsimile number for the relevant *facility*; and~~

(~~5~~4) an electronic mail address for the relevant *facility*.

(b) A *controller* must maintain the speech communication channel installed in accordance with subclause 3.3.4.3(c) or subclause 3.4.9~~(d)~~(c) in good repair and must investigate any fault within 4 hours, or as otherwise agreed with the *NSP*, of that fault being identified and must repair or procure the repair of faults promptly.

(c) Where required by the *NSP* a *controller* must establish and maintain a form of electronic mail *facility* as approved by the *NSP* for communication purposes.

(d) The *NSP* must, where necessary for the operation of the *transmission* and *distribution system*, advise *controllers* of nominated persons for the purposes of giving or receiving *operational communications*.

(e) Contact details to be provided by the *NSP* in accordance with subclause 5.9.2(d) include position, telephone numbers~~, a facsimile number~~ and an electronic mail address.

…

Schedule 15: Fault Level Requirements and Equipment Ratings [Issue 28]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 28' in the HTR Workbook. An issue paper was presented on 14 November 2024.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

The HTR Working Group undertook a high-level review of fault level requirements and fault level management in the Harmonised Technical Rules considering:

- minimum fault rating requirements for Transmission plant at significant network nodes; and
- potential requirements for limitations on maximum fault levels on the system and guidance on the calculation of fault levels.

After this review, the working group determined updates to the HTR were required.

Amendments to clause 3.2.1, including Tables 3.1 and 3.2, specify the minimum Short Time Withstand Current and Short Circuit Breaking Current for new equipment on transmission and distribution networks.

3.2.1 Power system performance standards

…

(f) Fault Levels

(1) A controller connected to the transmission system, may not install or connect equipment at the connection point that is rated for a maximum fault current lower than that specified in the access contract in accordance with the network planning criteria.

(2) A controller connected to the distribution system, who is not (and is not using the connection point to supply) a small use customer, must not install equipment at the connection point that is rated for a maximum fault current lower than that specified in the network planning criteria unless a lower maximum fault current is agreed with the NSP and specified in the access contract.

{Note: Where a controller's equipment increases the fault levels in the transmission system, responsibility for the cost of any upgrades to the equipment required as a result of the changed power system conditions will be dealt with by commercial arrangements between the NSP and the controller.}

(3) *Equipment* commissioned after [date] must meet or exceed the Short Time Withstand Current and Short Circuit Breaking Current in Tables 3.1 and 3.2. *NSPs* may specify a higher requirement based on *power system* planning and fault level studies in accordance with Section 3.2.6, Section 5.4.1 and *GEIP*.

Table 3.1 – For equipment connected to the transmission system

	System Voltage

	330kV	220kV	132kV	66kV	33kV	22kV	11kV
Short Time Withstand Current / Short Circuit Breaking Current (kA rms)	50	25	40	25	16	16	25
Short Circuit Duration (s)	1	1	1	3	3	3	3

{Note: Consistent with the definition of *transmission system* there is sometimes equipment operated at *voltages* below 66kV which is used 'primarily for, or in connection with, or to control, the transportation of electricity at *voltages* of 66 kV or higher' and hence the need to specify minimum fault withstand ratings for equipment connected to the *transmission system* operating at voltages less than 66kV.}

Table 3.2 – For equipment connected to the distribution system

	System Voltage		
	33kV	22kV	11kV
Short Time Withstand Current / Short Circuit Breaking Current (kA rms)	13.1	16	25
Short Circuit Duration (s)	3	3	3

…

3.3.4.5 Voltage control system

…

(f) The performance characteristics required for AC exciter, rotating rectifier and *static excitation systems* are specified in Table ~~3.1~~ 3.3; and

(g) The performance characteristics required for the *voltage* or *reactive power control systems* of all non-*synchronous generating units* are specified in Table ~~3.2~~ 3.4.

…

Table ~~3.1~~ 3.3 – Synchronous generator excitation control system performance requirements

Performance Item	Units	Static Excitation	AC Exciter or Rotating Rectifier	Notes
Sensitivity: A sustained 0.5% error between the *voltage* reference and the sensed *voltage* must	Open loop		200 minimum	1

Performance Item	Units	Static Excitation	AC Exciter or Rotating Rectifier	Notes
produce an excitation *voltage change* of not less than 1.0 per unit.	gain (ratio)	200 minimum		
Field *voltage* rise time: Time for field *voltage* to rise from rated *voltage* to excitation ceiling *voltage* following the application of a short duration impulse to the *voltage* reference.	second	0.05 maximum	0.5 maximum	2, 4
Settling time with the *generating unit* unsynchronised following a disturbance equivalent to a 5% step *change* in the sensed *generating unit* terminal *voltage*.	second	1.5 maximum	2.5 maximum	3
Settling time with the *generating unit* synchronised following a disturbance equivalent to a 5% step *change* in the sensed *generating unit* terminal *voltage*. Must be met at all operating points within the *generating unit* capability.	second	2.5 maximum	5 maximum	3
Settling time following any disturbance which causes an excitation limiter to operate.	second	5 maximum	5 maximum	3

{Note:

1. One per unit excitation *voltage* is that field *voltage* required to produce nominal *voltage* on the air gap line of the *generating unit* open circuit characteristic (Refer IEEE Standard 115-1983 - Test Procedures for Synchronous Machines). *Excitation control system* with both proportional and integral actions must achieve a minimum equivalent gain of 200.
2. Rated field *voltage* is that *voltage* required to give nominal *generating unit* terminal *voltage* when the *generating unit* is operating at its maximum continuous rating. Rise time is defined as the time taken for the field *voltage* to rise from 10% to 90% of the increment value.
3. Settling time is defined as the time taken for the *generating unit* terminal *voltage* to settle and stay within an error band of $\pm$10% of its increment value.
4. Field *voltage* means *generating unit* field *voltage*.}

Table ~~3.2~~ 3.4 – Non-synchronous generator voltage or reactive power control system performance requirements

Performance Item	Units	Limiting Value	Notes
***Sensitivity*:** A sustained 0.5% error between the reference *voltage* and the sensed *voltage* must produce an output *change* of not less than 100% of the *reactive power generation* capability of the *generating unit,* measured at the point of control.	Open loop gain (ratio)	200 minimum	1
Rise time: Time for the controlled parameter (*voltage* or *reactive power* output) to rise from the initial value to 90% of the *change* between the initial value and the final value following the application of a 5% step *change* to the *control system* reference.	second	1.5 maximum	2
***Small disturbance* settling time** Settling time of the controlled parameter with the *generating unit connected* to the *transmission or distribution network* following a step *change* in the *control system* reference that is not large enough to cause saturation of the controlled output parameter. Must be met at all operating points within the *generating unit's* capability.	second	2.5 maximum	3
***Large disturbance* settling time** Settling time of the controlled parameter following a *large disturbance*, including a *transmission or distribution network* fault, which would cause the maximum value of the controlled output parameter to be just exceeded.	second	5 maximum	3

{Note:

1. A *control system* with both proportional and integral actions must be capable of achieving a minimum equivalent gain of 200.
2. The controlled parameter and the point where the parameter is to be measured must be agreed and included in the relevant *access contract*.
3. Settling time is defined as the time taken for the controlled parameter to settle and stay within an error band of ±10% of its increment value.

…

3.4.5 Requirements of clause 3.3 applicable to small power stations

Table ~~3.3~~ 3.5 lists provisions of clause 3.3 that apply to small *power stations* in addition to the requirements of clause 3.4.

Table ~~3.3~~ 3.5- Specific paragraphs of clause 3.3 applicable to distribution-connected generating units rated up to 10 MW

Clause	Requirement
3.3.3.1	*Reactive power capability*
3.3.3.3	*Generating unit* response to disturbances in the Power system
	Except that *power stations* with less than 150 kW aggregate capacity need not comply with subclauses 3.3.3.3(c) and 3.3.3.3(g) unless directed otherwise by the *NSP*.
3.3.3.8	*Protection* of *generating units* from *power system* disturbances
3.3.4.4	*Frequency control*
	Except that *non-dispatchable induction generating units* need not comply with subclauses (a), (b), (d) and (e)(2) and f(2); and
	Except that *non-synchronous power station*s with less than 150 kW aggregate capacity do not have to comply with subclauses (a), (b) and (d)
3.3.4.5	*Voltage control system*
	Except that *non-synchronous generating units* may be fitted with *power factor control systems* utilising modern technology, unless *power system* studies show that fast acting *voltage* and/or *reactive power control systems* complying with subclause 3.3.4.5(c) are required.
	Subclause 3.3.4.5.(e) does not apply; and
	For *power station*s with a capacity of less than 150 kW subclause 3.3.4.5.(f) is replaced with:
	Generating units must have *voltage control systems* that ensure that the requirements of clause 3.4.8 are met at the *connection point*.

…

Schedule 16: Adequacy of requirements for system restart arrangements [Issue 29]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 29' in the HTR Workbook. An issue paper was presented on 14 November 2024.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

The PNR already allows a relaxation of frequency and voltage operating standards during the highly abnormal system conditions associated with system restart scenarios, where it is impractical in these scenarios to maintain these standards.

Rule 162 is amended to include a drafter's note that identifies system restart as an example of a situation in which it is impractical to Maintain the Power System within the Technical Envelope. The proposed note provides interpretation guidance without changing the legal meaning of the rule.

162 The system security objective

The **"system security objective"** is to —

(a) Maintain the Power System Inside the Technical Envelope where practicable, and otherwise Promptly return it to Inside the Technical Envelope; and

(b) Maintain the Power System in a Secure State where practicable, and otherwise return it to a Secure State as soon as practicable; and

(c) otherwise — to a GEIP standard Maintain, and to a GEIP standard seek to improve, Security and Reliability.

{For example, system restart is used in a situation in which it may be impractical to Maintain the Power System inside the Technical Envelope, with the following considerations —

- The system is usually restarted using one Generating Unit at a time ("black starting Generator"), energising portions of the Transmission Network by working outward from the black starting Generator.
- Prior to commencing the restart, the system is often fractured into Islands.
- The above factors mean there is little generation on the system, resulting in unusually low system strength (ie low capacity to maintain voltage).
- Consequently, any event on the restarting Network is likely to cause material frequency and/or voltage fluctuations. This may include actions to switch on substation feeders to restore supply.}

…

Schedule 17: Interaction between the HTR and CPC rules in the PNR [Issue 30]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 30' in the HTR Workbook. An issue paper was presented on 14 November 2024.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

Rule 274A(2)(e) is amended to clarify that a Non-Compliant Component remains non-compliant notwithstanding any agreed CPC Measures.

274A Concept, definitions and eligibility

(1) {**Concept**} In this Subchapter 9.3, "Connection Point Compliance" means an arrangement in which Equipment which is assessed under Subchapter 9.2 to include one or more Non-Compliant Components is nonetheless permitted to Connect to the NWIS, because the Equipment's Controller or the Host NSP, or both, implement measures which have been agreed between the Controller, the ISO and the Host NSP to ensure that the Facility as a whole complies with these Rules at its Connection Point, despite the non-compliance of the component.

(2) {**Definitions**} In these rules —

(a) **"CPC Facility"** means Eligible Equipment for which CPC Measures have been agreed under rule 274C and have been implemented; and

(b) **"CPC Measures"** for a CPC Facility means the measures which have been agreed for the facility between the Connection Applicant, the Host NSP and the ISO under rule 274C and recorded in writing under rule 274C(3)(a); and

(c) **"Eligible Equipment"** means a collection of Equipment which meets the requirements set out in rule 274A(3), as modified under rule 274A(4) if applicable; and

(d) **"Host NSP"** means the NSP of the NWIS Network to which the CPC Facility (or, if applicable, the Equipment which is proposed to become, or was previously, a CPC Facility) is, is to be, or was Connected; and

(e) **"Non-Compliant component"** means Equipment or a component of Equipment which (whether due to its operation, characteristics, configuration, performance or capacity) does not comply with these Rules (including the Harmonised Technical Rules), and the non-compliance is not the subject of an exemption under these rules. Equipment or a component of Equipment remains non-compliant notwithstanding any agreed CPC Measure.

(3) {**Eligibility**} A collection of Equipment is eligible for Connection Point Compliance if together the pieces of Equipment —

(a) are electrically interconnected with each other; and

(b) are under the control of a single Controller; and

(c) do not include any Network component which is Covered; and

(d) include at least one Non-Compliant Component; and

(e) subject to rule 274A(4), are connected to the NWIS by a Single Connection Point.

…

Schedule 18: Update CFCTs to reflect system changes and approved derogations [Issue 32]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 32' in the HTR Workbook. An issue paper was presented on 14 November 2024.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

Table 2.10 has been amended to update Critical Fault Clearing Times in the NWIS, to align with other technical rules and reflect the findings of an independent study not captured during the development of the HTR. Practically, this means removing HP-Rio tie lines so that Table 2.10 lists the maximum Total Fault Clearance Times for systems that are 33kV (or below) as 300ms.

2.6.4 Maximum total fault clearance times

…

Table 2.10 – Maximum total fault clearance times (ms)

		~~New~~ ~~*Equipment*~~ *Equipment* commissioned after [date] **No CB Fail**	~~New~~ ~~*Equipment*~~ *Equipment* commissioned after [date] **CB Fail**
220 kV	Local end	120	430
	Remote end	140	430
132 kV	Local End	120	430
	Remote end	140	430
66 kV	Local End	120	430
	Remote end	140	430
~~33 kV HP-Rio tie lines~~	~~Local End~~	~~105~~	~~Not specified~~
	~~Remote End~~	~~105~~	~~Not specified~~
33 kV and below	Local End	300	Not specified
	Remote End	300	Not specified

Table 2.11 – Alternative Maximum total fault clearance times (ms)

		~~New~~ ~~*Equipment*~~ *Equipment*	~~New~~ ~~*Equipment*~~ *Equipment*

		commissioned after [date] **No CB Fail**	commissioned after [date] **CB Fail**
132 kV	Local end	120	270
	Remote end	400	565
66 kV	Local end	105	270
	Remote end	400	565

…

Schedule 19: Special Protection Schemes [Issue 35]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 35' in the HTR Workbook. An Issue paper was presented on 10 September 2025.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

New definitions of 'Non-credible Contingency Event', 'Protected Event' and 'Special Protected Scheme' have been introduced to clause 8 of the PNR and clause 1.5 of the HTR.

Rule 198A has been introduced outlining when the ISO may determine that a non-credible contingency event should be treated as a Protected Event and the requirements for an NSP to respond, whether by implementing a Special Protection Scheme, providing an alternative method of response, or why no action is necessary.

Clauses 2.2.1(d) and 2.2.1(e) have been amended to account for the new defined term non-credible contingency event and correctly align with the style of the rest of the HTR.

New clause 2.3.10 is introduced to outline how special protection schemes will operate and be maintained.

New clause 4.1.8 is introduced to outline how special protection schemes, and the relevant facilities and equipment, will be tested by the relevant NSPs.

Pilbara Networks Rules

Subchapter 1.2 – Interpretation

{A word or phrase defined in the Act or the Regulations has the same meaning when used in these Rules.}

8 Glossary

(1) A word or phrase defined below has the meaning given —

…

Credible Contingency {also **Credible Contingency Event**}: Means a Contingency event —

a) which the Protocol Framework identifies as a Credible Contingency event; or

b) which the ISO Control Desk otherwise considers to be reasonably possible in the surrounding circumstances.

Without limiting the generality of this definition, examples of Credible Contingency events are likely to include —

i) the unexpected automatic or manual disconnection of, or the unplanned reduction in capacity of, one operating Generating Unit; or

ii) the unexpected disconnection of a Transmission Element anywhere on the Power System.

…

Non-Credible: In relation to an event or other thing, means not Credible.

Non-Credible Contingency Event (also **Non-Credible Contingency**): In relation to a Contingency, means not a Credible Contingency.

Normal Frequency Tolerance Band: Is set out in the Harmonised Technical Rules.

…

Promptly: Is defined in rule 10.

Protected Event: Means a low likelihood, high consequence Non-Credible Contingency Event identified under rule 198A(1) that has been classified, on the recommendation of the ISO, as warranting the consideration of remedial actions because of its potential to materially affect Power System Security.

Protected Provision: Means a provision of these Rules identified as such in Appendix 2.

…

Security {also "Secure"}: Means the Power System's ability to withstand disturbances, including ~~include~~ electric short circuits, unanticipated loss of facilities or Network Elements, or other rapid changes such as in intermittent generation.

Security Limit: Means a technical limit on the operation of the whole of, or a region in, the Power System, necessary to Maintain Security, including both static and dynamic limits, and including limits to allow for and to manage constraints and contingencies.

Settlement Period: Means a calendar month.

Special Protection Scheme: Means an automatic or semi-automatic control scheme which activates in response to an identified Protected Event, and to implement predetermined corrective actions to maintain Power System Security, including the Frequency Operating Standards.

SRESS: Is defined in rule 213.

…

198A Protected Events and Special Protection Schemes

(1) If the ISO considers, following discussions or an investigation under Subchapter 7.6, that a Non-Credible Contingency Event should be classed as a Protected Event, it must identify and recommend, where applicable, adoption of any Special Protection Scheme(s) that, should a Protected Event occur, would maintain Power System Security.

(2) In forming its recommendation under Rule 198A(1), the ISO must consider, in consultation with the relevant NSP:

(a) the technical feasibility of a Special Protection Scheme to mitigate or prevent the identified Protected Event;

(b) the Special Protection Scheme's expected performance and reliability;

(c) the practicality of implementing and maintaining the recommended Special Protection Scheme;

(d) whether the Special Protection Scheme would contravene any requirements in the HTR; and

(e) the comparative efficiency and effectiveness of the recommended Special Protection Scheme relative to other operational or investment options.

(Note — Analysis of any proposed Special Protection Schemes should be conducted with the aim of having a balanced approach to reducing the risks of low-likelihood / high-consequence events while also avoiding the use of ESS, constraint rules, or manual load shedding measures where feasible).

(3) The ISO must provide a preliminary report to the NSP, outlining its considerations and recommendations, and specify a timeframe within which the NSP must –

(a) inform the ISO that it will invest in the proposed Special Protected Scheme, and the timeframe required to implement it; or

(b) provide an alternative proposal to respond to the identified Protected Event; or

(c) propose to the ISO that no further action is required.

(4) Subject to requirements in sub-chapter 11.2, the ISO must publish its report and the relevant NSP's decision.

(5) The ISO must keep a public record of all identified Protected Events and any Special Protection Schemes in place to mitigate them.

(6) The ISO may conduct reviews into identified Protected Events and the ongoing adequacy of a Special Protection Scheme to respond to a Protected Event.

(7) If a review of a Protected Event or a Special Protection Scheme is conducted under Rule 198(6), the ISO may consult with relevant NSPs and determine:

(a) to retain the identified event as a Protected Event and all relevant Special Protection Schemes;

(b) revise the Special Protection Scheme to better respond to an identified Protected Event;

(c) that a Non-Credible Contingency Event should no longer be classed as a Protected Event; or

(d) remove a Special Protection Scheme if it is no longer required to respond to a Protected Event.

(8) Subject to requirements in Subchapter 11.2 and consultation with the NSP, the ISO must publish its report of its review conducted under Rule 198(6).

…

Harmonised Technical Rules

1.5 Interpretation

…

nomenclature standards	means the standards approved by the *NSP* relating to numbering, terminology and abbreviations used for information transfer between *controllers* as provided for in clause 5.11.
non-credible contingency event	is defined in the *Pilbara networks rules*.
non-dispatchable generating unit	means a *generating unit* that in its satisfactory normal operating state is not capable of closely controlling its real power output.

…

proactive load shedding scheme	means a pre-planned scheme for reducing or disconnecting load from the power system.
protected event	is defined in the *Pilbara networks rules*.
protection	means the detection, limiting and removal of the effects of *primary equipment* faults from the *power system*; or the apparatus, device or system required to achieve this function.

…

spare capacity	means any portion of firm capacity or non-firm capacity not committed to existing *controllers*.
special protection scheme	is defined in the *Pilbara networks rules*.
standard consultation procedure	is defined in the *Pilbara networks rules*.

…

2.2.1 Frequency variations

…

(d) The *power system* must remain within the *frequency operating standards* under all credible *power system load* and generation patterns and the most severe ~~credible contingency event.~~ *credible contingency event*.

(e) Clause 2.2.1**Error! Reference source not found.** must be complied with, without the use of load shedding, unless:

~~a~~(1) access is unavailable to adequate spinning reserve procured and enabled in accordance with the *Pilbara networks rules*; or

~~b~~(2) an *island* forms in the *power system*, and access is unavailable within the *island* to adequate spinning reserve procured and enabled in accordance with the *Pilbara networks rules* — in which case *load*

shedding may be used to comply with clause 2.2.1**Error! Reference source not found.** within the *island*; or

~~c~~(3) a multiple *contingency event* occurs

…

2.3 Obligations of NSP in relation to power system performance

…

2.3.10 Design of special protection schemes

(a) Where an *NSP* elects to pursue a *special protection scheme* following a recommendation under the PNR, the *NSP* must ensure that the *special protection scheme* is designed, implemented and maintained in accordance with the principles in this Chapter and GEIP.

(b) The design must ensure:

(1) compatibility with existing protection and *control systems*;

(2) appropriate redundancy and fail-safe behaviour; and

(3) that any automatic actions operate within required timeframes to achieve the intended system *security* outcome.

(c) The NSP must maintain documentation describing the *protected event* that the scheme is designed to respond too, any trigger criteria, actions required by *controllers*, and any maintenance/testing programs.

…

4.1 Inspection and testing

…

4.1.8 Testing of Special Protection Schemes

(a) An *NSP* that implements a *special protection scheme* must test and maintain that scheme in accordance with documentation required under clause 2.3.10(c) and a *GEIP* standard.

(b) The *NSP* must, subject to clause 4.1.1, provide performance data and post-event reports to the *ISO*, following any activation or test of the *special protection scheme*.

(c) Where the *special protection scheme* is unavailable or out of service, the *NSP* must notify the *ISO* in line with Subchapters 7.3 and 7.4 of the *Pilbara networks rules*.

…

Schedule 20: Overall review of referenced standards [Issue 40]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'Issue 40' in the HTR Workbook. An issue paper was presented on 14 November 2024.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

Several of the standards referenced in the HTR are outdated, and some have undergone multiple revisions. Clauses 1.5, 2.2, 2.3, 3.2, 3.3, 3.4, 3.6 and Attachment 1 of the HTR have been updated to reflect that all standards referred to in the HTR are the most recent versions of those standards to maintain accuracy and relevance.

1.5 Interpretation

In these *Rules*:

(a) a word or phrase defined in the *Pilbara networks rules*, Act or the PNAC has the meaning given in those rules, that Act or that Code (as the case requires), unless redefined below; and

(b) the rules of interpretation in the *Pilbara networks rules* apply; ~~and~~

(c) all references to Australian and international standards within this document shall be interpreted in accordance with the latest published versions of the relevant standards, unless a specific edition is explicitly stated; and

(d) a word or phrase defined in the following table has the meaning given.

…

Pilbara networks rules	means the *Pilbara Networks Rules* made by the Minister under Part 8A of the *Electricity Industry Act 2004*, of which these Rules comprise Appendix 5.
PNAC	means the *Pilbara Networks Access Code ~~(2004)~~* made by the Minister under Part 8A of the *Electricity Industry Act 2004*
point of common coupling	means the point on the *network* at which Horizon Power requires compliance with the Technical Rules clauses 2.3.3(a) and 2.3.4(a). Under normal circumstances this compliance is required at the connection point, but Horizon Power may, at its sole discretion, allow the "point of common coupling" to be at a point on the network upstream from the connection point, where it is reasonable to do so in accordance with good electricity industry practice.

…

2.2.2 Steady State Power Frequency Voltage

…

Table 2.3 – Step – change voltage limits

…

{NOTES:

1. For example, capacitor switching, *transformer* tap action, motor starting, start-up and shutdown of *generating units*.
2. For example, tripping of *generating units*, *loads*, lines and other components.
3. ΔU_{dyn} is the dynamic *voltage change* which has the same meaning as in ~~AS/NZS 61000.3.7~~TR IEC 61000.3.7:.
4. U_N is the nominal *voltage*.}

2.2.3 Flicker

(a) Rapid *voltage* fluctuations cause *changes* to the luminance of lamps which can create the visual phenomenon called flicker. Flicker severity is characterised by the following two quantities, which are defined in ~~AS/NZS 61000.3.7:2001~~TR IEC 61000.3.7:

(1) P_{st} - short-term flicker severity term (obtained for each 10 minute period);

(2) P_{lt} - long-term flicker severity (obtained for each 2 hour period).

(b) Under normal operating conditions, flicker severity caused by *voltage* fluctuation in the *transmission* and *distribution system* must be within the planning levels shown in Table 2.4 for 99% of the time.

Table 2.4 – Planning levels for flicker severity

Flicker Severity Quantity	LV (415 V)	MV (≤ 35 kV)	HV-EHV (> 35 kV)
P_{st}	1.0	0.9	0.8
P_{lt}	0.8	0.7	0.6

{NOTES:

1. These values were chosen on the assumption that the transfer coefficients between MV or HV systems and LV systems are unity. The planning levels could be increased in accordance with ~~AS 61000.3.7 (2001)~~TR IEC 61000.3.7:
2. The planning levels in Table 2.4 are not intended to apply to flicker arising from *contingency* and other *uncontrollable* events in the *power system*, etc.}

2.2.4 Harmonics

Under normal operating conditions, the harmonic *voltage* in the *transmission* and *distribution systems* must not exceed the planning levels shown in Table 2.5 and Table 2.6 (as applicable) appropriate to the *voltage* level, whereas the inter harmonics *voltage* must not exceed the planning levels of ~~AS/NZS 61000.3.6 (2001)~~ TR IEC 61000.3.6:

…

Table 2.6 – Transmission planning levels for harmonic voltage in networks with system voltage above 35 kV (in percent of the nominal voltage)

Odd harmonics non multiple of 3		**Odd harmonics multiple of 3**		**Even harmonics**	
Order h	**Harmonic *voltage* %**	**Order h**	**Harmonic *voltage* %**	**Order h**	**Harmonic *voltage* %**
5	2	3	2	2	1.5
7	2	9	1	4	1
11	1.5	15	0.3	6	0.5
13	1.5	21	0.2	8	0.4
17	1	>21	0.2	10	0.4
19	1			12	0.2
23	0.7			>12	0.2
25	0.7				
>25	$0.2 + 0.5^{25}/_{h}$				
Total harmonic distortion (THD): 3 %					

Notes:

1. The planning levels in Table 2.5 and Table 2.6 are not intended to apply to harmonics arising from uncontrollable events such as geomagnetic storms, etc.

2. The total harmonic distortion (THD) is calculated from the formula:

$$THD = \frac{Unom}{} \sum \sqrt{40\ (Uh)2\ U1\ h=2}$$

Where:

U_{nom} = nominal *voltage* of a system

U_1 = fundamental *voltage*

U_h = harmonic *voltage* of order h expressed in percent of the nominal *voltage*

3. Table 2.5 and Table 2.6 are consistent with ~~AS 61000 (2001)~~ TR IEC 61000:

…

2.2.6 Electromagnetic interference

Electromagnetic interference caused by *equipment* forming part of the *transmission* and *distribution system* must not exceed the limits set out in Tables 1 and 2 of *Australian Standard* ~~*AS* 2344 (1997)~~AS 2344.

…

2.3 Obligations of NSP in relation to power system performance

…

2.3.3 Flicker

…

(b) *The NSP* must allocate contributions to limits no more onerous than the lesser of the acceptance levels determined in accordance with the stage 1 and the stage 2 evaluation procedures defined in ~~AS/NZS 61000.3.7 (2001)~~TR IEC 61000.3.7.

(c) If the *controller* cannot meet the contribution calculated by using the method of subclause 2.2.3(b), then the *NSP* may use, in consultation with the party seeking connection, the stage 3 evaluation procedure defined in ~~AS/NZS 61000.3.7 (2001)~~TR IEC 61000.3.7.

(d) *NSPs* must verify compliance of *controllers* with allocated flicker emission levels. The contribution may be assessed by direct measurement or by calculation from the available data for the *load* and the *power system*. In verifying compliance, measurements of flicker must be carried out according to ~~AS/NZS 61000.3.7 (2001)~~TR IEC 61000.3.7.

2.3.4 Harmonics

(a) To ensure that the harmonic or inter-harmonic level at any *point of common coupling* on the *network* does not exceed the maximum levels specified in clause 2.2.4, the *NSP* must, where necessary and after consultation with the relevant *controllers*, allocate harmonic emission limits to *controllers* in accordance with ~~*AS*/NZS 61000.3.6 (2001)~~TR IEC 61000.3.6.

…

(c) The measurement must be carried out according to ~~*AS*/NZS 61000.4.7 (1999)~~AS/NZS 61000.4.7. Harmonics must generally be measured up to h=40. However, higher order harmonics up to 100th order may be measured if the *NSP* reasonably considers them to be of material concern.

…

3 Technical requirements of user facilities

…

3.2 Requirements for all controllers

3.2.1 Power system performance standards

…

(e) Electromagnetic Interference

A controller must ensure that the electromagnetic interference caused by its equipment does not exceed the limits set out in Tables 1 and 2 of Australian Standard ~~*AS* 2344 (1997)~~AS 2344.

…

3.3 Requirements for connection of generating units > 10 MW

…

3.3.2 Provision of information

…

(b) For a covered network:

…

b the ~~*controller*~~*User Access Guide* published under the *PNAC* must set out clearly the information the *NSP* is likely to require under this clause 3.3.2.

3.3.3 Detailed technical requirements requiring ongoing verification

…

3.3.3.2 Generating unit performance standard

A *synchronous generating unit* or an *induction generating unit* must be designed to *generate* a constant *voltage* level with balanced phase *voltages* and harmonic *voltage* distortion equal to or less than permitted in accordance with either ~~*Australian Standard AS* 1359 (1997) "General Requirements for Rotating Electrical Machines"~~ AS 60034.1 "Rotating electrical machines Rating and performance" or a recognised equivalent international standard as agreed between the *NSP* and the *controller* if the *generating unit* was not *connected* to the *network.*

…

3.3.4 Monitoring and control requirements

…

3.3.4.5 Voltage control system

…

Table 3.1 – Synchronous generator excitation control system performance requirements

Performance Item	Units	Static Excitation	AC Exciter or Rotating Rectifier	Notes
Sensitivity: A sustained 0.5% error between the *voltage* reference and the sensed *voltage* must produce an excitation *voltage change* of not less than 1.0 per unit.	Open loop gain (ratio)	200 minimum	200 minimum	1
Field *voltage* rise time: Time for field *voltage* to rise from rated *voltage* to excitation ceiling *voltage* following the application of a short duration impulse to the *voltage* reference.	second	0.05 maximum	0.5 maximum	2, 4
Settling time with the *generating unit* unsynchronised following a disturbance equivalent to a 5% step *change* in the sensed *generating unit* terminal *voltage*.	second	1.5 maximum	2.5 maximum	3
Settling time with the *generating unit* synchronised following a disturbance equivalent to a 5% step *change* in the sensed *generating unit* terminal *voltage*. Must be met at all operating points within the *generating unit* capability.	second	2.5 maximum	5 maximum	3
Settling time following any disturbance which causes an excitation limiter to operate.	second	5 maximum	5 maximum	3

{Note:

1. One per unit excitation *voltage* is that field *voltage* required to produce nominal *voltage* on the air gap line of the *generating unit* open circuit characteristic (Refer ~~IEEE Standard 115-1983 - Test Procedures for Synchronous Machines~~IEEE 115). *Excitation control system* with both proportional and integral actions must achieve a minimum equivalent gain of 200.

…

3.4 Requirements for connection of small generating units to the distribution network (1000 kVA up to 10 MW)

…

3.4.8 Power quality and voltage change

…

(d) When operating unsynchronised, a *synchronous generating unit* in a small *power station* must generate a constant *voltage* level with balanced phase *voltages* and harmonic *voltage* distortion equal to or less than permitted in accordance with either ~~*Australian Standard AS* 1359 (1998) - "General Requirements for Rotating Electrical Machines"~~AS 60034.1 “Rotating electrical machines Rating and performance” or a recognised relevant international standard, as agreed between the *NSP* and the *controller*.

…

3.4.10.1 General

…

(l) *Generating units* that are only operated in parallel with the *distribution system* during *rapid bumpless transfer* must be protected by an independent timer that will *disconnect* the *generating unit* from the *distribution system* if the bumpless transfer is not successfully completed. Automatic transfer switches must comply with ~~*AS* 60947.6.2 (2004)~~ AS/NZS IEC 60947.6.2 “Low-voltage switchgear and controlgear Multiple function equipment - Control and protective switching devices (or equipment) (CPS)”. For the avoidance of doubt, *generating units* covered by this clause need not comply with subclauses (f) to (k) of this clause 3.4.10.1.

…

3.6 Requirements for connection of loads

…

3.6.8 Design requirements for consumers’ substations

…

(e) earthing of *primary equipment* in the *substation* must be in accordance with the *WA Electrical Requirements*, *AS* 2067 for *medium and high voltage equipment* or ~~AS/NZS 3000 (2000)~~ AS/NZS 3000 for *low voltage equipment*. The earthing system must satisfy these requirements without any reliance on the *NSP’s equipment*; Where it is not possible to design a compliant earthing system within the boundaries of a *consumer’s* plant, the *NSP* must provide a *consumer*, access to its easement for the installation of earthing conductors and stakes where it is practical to do so and provided that this is not precluded by any legal requirement.

…

Attachment 1 – Process for determining the content of these Attachments

…

4. Pending any such *publication* or making-available, the corresponding Attachment of the *Horizon Power Technical Rules* ~~of October 2020~~, read with appropriate amendments, may be used as a non-binding guideline.

…

Schedule 21: Replace references to ‘ancillary services’ with ‘essential system services’ [Issue 41]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as ‘Issue 41’ in the HTR workbook. An issue paper was presented on 14 November 2024.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

The defined term “ancillary service” is removed from clause 1.5. References to “ancillary service” have been changed to “essential system service” in clauses 3.1 and 3.2.

1.5 Interpretation

…

agreed capability	in relation to a *connection point* — means the capability to receive or send out *active power* and *reactive power* for that *connection point* determined in accordance with the relevant *access contract*.
~~**ancillary service(s)**~~	~~means an “essential system service” as defined in the *rules*.~~
augment	in relation to a *network* — means to increase the capability of the *network* to provide services.

…

3.1 Introduction

…

(c) The objectives of this chapter are to facilitate maintenance of the *power system* performance standards specified in clause 2.2, so that other *controllers* are not adversely affected, and so that personnel and *equipment* safety are not put at risk following, or as a result of, the connection of a *controller's equipment*.

{Note: The scope of these *Rules* does not include the technical requirements for the provision of ~~*ancillary*~~ *essential system services* under these *rules* or a commercial arrangement with the *NSP*. *controllers* who provide these ~~*ancillary*~~ *essential system services* may be required to comply with technical requirements over and above those specified in this chapter. These additional requirements will be specified in the provisions of these *rules* dealing with the ~~*ancillary*~~ *essential system service* or in the relevant ~~*ancillary*~~ *essential system services* contract.}

3.2 Requirements for all controllers

…

3.2.5.2 Specific protection requirements for generators’ facilities

…

(d) The *generator's protection system* and other controls must achieve the following functions:

…

(3) prevention of the *generator's generating unit* from energising de-energised *NSP equipment*, or energising and *supplying* an otherwise isolated portion of the *network* except where a *generator* is *directed* under the *Pilbara networks rules* to provide a black start ~~*ancillary*~~ *essential system service*;

…

Schedule 22: Clarification of 'active power output' in cl. 3.3.4.4(e)(1) [Issue I2025.3]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'I2025.3' in the HTR workbook.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

Subclause 3.3.4.4(e)(1)(A) currently refers to "active power output". This amendment is to clarify that this is a reference to "*rated* active power output".

A note under 3.3.4.4(2) has been added to clarify that site specific maximum ambient temperature when testing the control range outlined in clause 3.3.4.4(e)(1).

3.3.4.4 Frequency control

…

(e) **Control range**

(1) *For dispatchable generating units:*

(A) The overall response of a *synchronous generating unit* for *power system frequency* excursions must be settable and ~~be capable of achieving an increase in the *generating unit's active power* output of not less than 5% for a 0.1 Hz reduction in *power system frequency*~~ be capable of achieving an increase in *synchronous generator's unit's active power* output of not less than 5% of its rated *active power* output for a 0.1Hz reduction in *frequency* (4% droop) for any initial output up to 85% of rated *active power* output.

(B) A *synchronous generating unit* must also ~~be capable of achieving a reduction in the *generating unit's active power* output of not less than 5% for a 0.1 Hz increase in system frequency~~ be capable of achieving a reduction in *synchronous generator's unit's active power* output of not less than 5% of its rated *active power* output for a 0.1Hz increase in system frequency provided this does not require operation below the *technical minimum*.

(C) For initial outputs above 85% of rated *active power* output, a *generating unit's* response capability must be included in the relevant *access contract*, and the *generator* must ensure that the *generating unit* responds in accordance with that *access contract.*

(D) *Thermal generating units* must be able to sustain *load changes* of at least 10% for a *frequency* decrease and 30% for a *frequency* increase if *changes* occur within the above limits of output.

(2) For *non-dispatchable generating units*, a *generating unit* must be capable of achieving a reduction the *generating unit*'s *active power* output for an increase in system *frequency*, provided the latter does not require operation below *technical minimum*.

{Notes Unless operating restrictions have been agreed in accordance with subclause 3.1(b), the NSP may assume the site specific maximum ambient temperature as determined by the NSP with a 1% probability of exceedance, or 50 degrees Celsius, when assessing compliance with the requirements of clause 3.3.4.4(e)(1).}

…

Schedule 23: Correcting definition of 'point of common coupling' [Issue I2025.7]

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group as 'I2025.7' in the HTR workbook.

Draft Amending Rules were provided to Working Group members on 23 January 2026 and comments were received on 23 February 2026.

The current definition of "point of common coupling" is specific to Horizon Power. The definition is amended so that it applies to all Network Service Providers (NSPs).

1.5 Interpretation

…

point of common coupling	means the point on the *network* at which ~~Horizon Power~~ the *NSP* requires compliance with the Technical Rules clauses 2.3.3(a) and 2.3.4(a). Under normal circumstances this compliance is required at the connection point, but ~~Horizon Power~~ the *NSP* may, at its sole discretion, allow the "point of common coupling" to be at a point on the network upstream from the connection point, where it is reasonable to do so in accordance with good electricity industry practice.

…

Schedule 24: Introducing requirement to provide EMT models

Explanatory Note

This Schedule was developed through the EPNR HTR Working Group, and was discussed at the 2 July 2026 Working Group meeting.

New clause 3.3.9(a)(g) introduces an ongoing obligation on generators to provide and maintain the software models required by the power system modelling procedure for the duration of their connection to the network. This ensures that generators provide new, updated or replacement models where required to reflect changes in modelling requirements over time, including, for example, where the power system modelling procedure introduces a requirement for an electromagnetic transient (EMT) model.

3.3.9 Computer model

(a) A *generator* must provide to the *NSP* a software model of each *generating unit* suitable for use in the *ISO*'s *power system model*. The model must automatically initialise its parameters from *load* flow simulations. Once a simulation case has been compiled, changes in the *load* flow such as changes in *voltage*, *generating unit* output (or the consumption of *consumer equipment*), voltage set point must not require the study case to be recompiled. The *NSP* must make the model available to the *ISO* for inclusion in the standard software package library, in accordance with the *power system modelling procedure*. The source code of the model must also be provided.

(b) *Generators* must demonstrate to the *NSP's* satisfaction, and the *NSP* must (with such assistance from the *generator* as the *NSP* reasonably requires) demonstrate to the *ISO's* satisfaction, that the model adequately represents the performance of the *generating unit* over its *load* range and over the system *frequency* operating range of clause 2.2.1, Table 2.1. The normal method of model verification is through testing.

(c) The structure and parameter settings of all components of the turbine and excitation control *equipment* must be provided to the *NSP* in sufficient detail to enable the dynamics of these components to be characterised in the computer model for short and long term simulation studies. This must include a control block diagram in suitable form to perform dynamic simulations and proposed and final parameter settings for the turbine and *excitation control systems* for all expected modes of *turbine control system* operation. The final parameter settings must not be varied without prior approval of the *NSP*.

(d) The applicable structure and parameter settings include:

(1) speed/load controller;

(2) key *protection* and control loops;

(3) actuators (for example hydraulic valve positioning systems); and

(4) limiters.

(e) A *generating unit* may be connected to the *network* if:

(1) the requirements of clauses **Error! Reference source not found.** to 0 are fully complied with; or

(2) the *NSP*, acting reasonably, has agreed with the *controller* of the *generating unit*, in the relevant *access contract* or otherwise, on alternative arrangements to provide a replacement compatible software model of the *generating unit* should the *NSP* or *ISO* upgrade or *change* its *power system* simulation software.

(f) A *generator* that was *connected* to the *network* prior to the *Rules commencement date*, and which has not fully complied with the requirements of subclauses (a) to (d) of this clause 3.3.9, must support the computer model for *changes* in the nominated software for the duration of its connection to the *network*.

(g) A *generator* must, for the duration of its *connection* to the *network*, provide and maintain the software models required by the *power system modelling procedure*, including by providing any new, updated or replacement models required under that procedure.

…

GOVERNMENT OF WESTERN AUSTRALIA

Department of Energy and Economic Diversification

Energy Policy WA

Attachment 2 – Update on ISO deliverables

Pilbara Advisory Committee (**PAC**) Meeting 2026_09_17

Table 1: ISO no-regrets deliverables status update

Activity	Deliverables	Progress to date	Next steps
Outage planning framework	The Draft EPNR Implementation Plan assigns the following activities to the ISO: • Action 15 – Develop and consult on outage coordination process, including risk framework • Action 16 – Develop criteria for outage equipment list • Action 17 – Develop procedure to help participants identify outage impacts	The outage planning framework will be progressed through EPNR Working Group meeting to be held on: • 23 September 2026 • 14 October 2026 • 4 November 2026 The ISO will chair the meetings and prepare agenda papers and minutes. The meetings will be a workshop-style meeting and Working Group members are encouraged to extend invitations to subject matter experts within their organisation. In-person attendance is strongly encouraged, with hybrid participation available where required. The initial phase of work will focus on: • the Rule changes required to support the outage coordination process and creation of the system risk assessment framework.	The proposed outage planning framework, including the policy positions and supporting Rule changes, will be incorporated into the broader EPNR Consultation Paper. Following consultation and completion of the Rule change process, the ISO will separately develop the supporting procedure using the standard procedure change processes, including the criteria for the outage equipment list, guidance to assist participants in identifying outage impacts, timeframes and other procedural matters.
NSP-to-NSP connections	EPNRWG Action item 7 May: • ISO to provide its proposed list of minimum technical requirements to be measured at the connection point as part of the assessment of an NSP-to-NSP connection.	The ISO has prepared a Concept Draft of a proposed new Chapter 6 'Requirements for Connection Point Compliance' for the Harmonised Technical Rules. The proposed Chapter 6 includes: • Definitions (CPC System, production system/unit, generating system, integrated resource system, bidirectional unit, etc.); • General power system security principles; • Technical obligations for CPC Systems, including reactive power capability, disturbance ride-through, protection systems, frequency control, voltage and reactive power control, active power control, short circuit ratio, remote monitoring, high-speed data recorders, and power system modelling; • ISO responsibilities relating to system strength and inertia; and • Other coordination matters, including connection processes, cost allocation, outage management, and notification obligations. The paper presents a set of concepts intended to support the renewable energy	The Concept Draft is a preliminary proposal is intended to help identify changes that may be required to the Rules, Procedures, Guidelines, and related instruments to support implementation. The ISO will work with DEED on the processes for industry consultation on the Concept Draft to align with the broader timeline for the EPNR reform process.

		transition in the NWIS. While some of the regulatory matters may ultimately be addressed elsewhere within the Pilbara regulatory framework, they have been brought together for ease of consideration.	
Long-term planning / System strength framework	The Draft EPNR Implementation Plan assigns the following activities: • Activity 10 – Rule change to require ISO to publish the annual Pilbara System Plan and the Coordinator to publish a Pilbara Integrated System Plan (EPWA deliverable) The Draft EPNR Implementation Plan assigns the following activities to the ISO: • Action 44 – Develop fault level requirements for the NWIS • Action 48 – Rule changes to amend HTRs to specify fault level requirements	The EPNR reform program is currently considering the future scope and timing of the Chapter 10 Network Planning requirements.	To be considered as part of the Tranche 0 Rule amendments.
ISO Control Desk	The Draft EPNR Implementation Plan assigns the following activities to the ISO: • Action 11 – Develop project plan to bring control desk in-house	A draft Control Desk Transition Project Plan has been prepared by consultants and is under review by the ISO. The consultant is preparing a Project Initiation Plan, which includes: • Project definition – scope, objectives and principles, constraints and assumptions; • Project schedule – identifies issues, key decision points, dependencies and critical path; • Project reform budget and resourcing plan (+/- 50%); • Identifies project risks; and • Governance and reporting framework which supports informed and timely decision making The Project Initiation Plan will identify the issues which will need to be resolved in transitioning to an in-house ISO control desk. The plan will not recommend resolution of the issues, but step out the process, timing and interdependencies for resolution.	Stakeholder consultation on the Project Initiation Plan through the EPNR Working Group and a public consultation process. The Project Initiation Plan will outline the key decision points in the transition project, where industry consultation will need to occur.