

Inertia Requirements Methodology

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Current version release details

Version	Effective date	Summary of changes
2.0	1 December 2024	Revised for the <i>National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 No. 9</i> , accounting for changes to the National Electricity Rules inertia framework, including the following amendments to the Inertia Requirements Methodology: <ul style="list-style-type: none"> • A NEM-wide inertia floor for interconnected operation; and • Removal of restrictions on the procurement of synthetic inertia.

Note: There is a full version history at the end of this document.

1. Introduction

1.1. Purpose and scope

This is the *Inertia Requirements Methodology (Methodology)* made under clause 5.20.4 of the National Electricity Rules (NER).

This Methodology has effect only for the purposes set out in the NER. The NER and the *National Electricity Law (NEL)* prevail over this Methodology to the extent of any inconsistency.

This Methodology provides the process AEMO uses to determine the *inertia requirements* for each *region* of the National Electricity Market (NEM). This includes:

- Description of the modelling and analysis methodologies AEMO will use to determine the *system-wide inertia level*.
- Overview of *inertia sub-networks* and the process to declare them.
- Description of the methodology AEMO will use to allocate the *system-wide inertia level* to each *inertia sub-network*.
- Description of the modelling and analysis methodologies AEMO will use to determine the *satisfactory inertia level* for each *inertia sub-network*.
- Description of the modelling and analysis methodologies AEMO will use to determine the *secure inertia level* for each *inertia sub-network*.
- Description of the methodology AEMO will use to determine the *sub-network islanding risk* for each *inertia sub-network*.
- Information on the types of *inertia support activities* that AEMO will consider if requested by an *Inertia Service Provider*.
- Description of each kind of *inertia network service*, the relevant performance parameters and requirements, and the process and requirements for AEMO to approve the equipment through an *inertia network services specification*.

1.2. Glossary and interpretation

1.2.1. Glossary

Terms defined in the *National Electricity Law* and the NER have the same meanings in this Methodology unless otherwise specified in this clause. Terms defined in the NER are intended to be identified in this Methodology by italicising them, but failure to italicise a defined term does not affect its meaning.

In addition, the words, phrases and abbreviations in the table below have the meanings set out opposite them when used in this Methodology.

Term	Definition
1s FCAS	1-second FCAS markets, also referred to very fast FCAS (VFFCAS)

Term	Definition
AC	alternating current
Acceptable Frequency	The <i>frequency</i> at all energised <i>busbars</i> of the <i>power system</i> is within the <i>normal operating frequency band</i> , except for brief excursions outside the <i>normal operating frequency band</i> which remain within the <i>normal operating frequency excursion band</i>
AEMC	Australian Energy Market Commission
Amending Rule	National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 No. 9 ¹ . All rules references in the document are as per this amendment.
AVR	automatic <i>voltage</i> control
BESS	battery energy storage system/s
CMLD	composite <i>load</i> model
Contingency FCAS	Each of the following: <ul style="list-style-type: none"> • <i>Very fast raise service.</i> • <i>Very fast lower service.</i> • <i>Fast raise service.</i> • <i>Fast lower service.</i> • <i>Slow raise service.</i> • <i>Slow lower service.</i> • <i>Delayed raise service.</i> • <i>Delayed lower service.</i>
DC	direct current
DMAT	dynamic model acceptance test
DPV	distributed photovoltaics
EMT	electromagnetic transient
ESOO	Electricity Statement of Opportunities
Fast FCAS	<i>fast raise service</i> and <i>fast lower service</i>
FCAS	<i>frequency</i> control ancillary service/s
FFR	<i>fast frequency</i> response
FOS	<i>frequency</i> operating standard
FRT	fault ride-through
Generation event	Any of the following events: <ol style="list-style-type: none"> 1. A synchronisation of a <i>generating unit</i> of more than the <i>generation</i> event threshold of: <ol style="list-style-type: none"> a) for the Mainland: 50 megawatts (MW). b) for Tasmania: 20 MW. 2. An event that results in the sudden, unexpected and significant increase or decrease in the <i>generation</i> of one or more generating systems totalling more than the <i>generation</i> event threshold for the <i>region</i> in aggregate within no more than 30 seconds. 3. The <i>disconnection</i> of <i>generation</i> as the result of a <i>credible contingency event</i> (not arising from a <i>load</i> event, a <i>network</i> event, a separation event or part of a multiple <i>contingency event</i>), in respect of either a single generating system or a single dedicated <i>connection</i> asset providing <i>connection</i> to one or more generating systems.
GPSRR	General Power System Risk Review
HIL testing	Hardware-in-the-loop testing. Physical testing of a device that involves placing the device in a controlled bench test where its outputs are observed and measured.

¹ AEMC, 'Improving security frameworks for the energy transition', at <https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition>.

Term	Definition
Hz	hertz
IBR	inverter-based resource/s
Island	A part of the <i>power system</i> that includes <i>generation, networks, and load</i> , for which all of its alternating current <i>network connections</i> with other parts of the <i>power system</i> have been disconnected.
ISP	Integrated System Plan
Load event	For the Mainland: <i>connection or disconnection</i> of more than 50 MW of <i>load</i> not resulting from a <i>network event, generation event, separation event</i> or part of a multiple <i>contingency event</i> . For Tasmania: either a change of more than 20 MW of <i>load</i> , or a rapid change of flow by a high <i>voltage</i> direct current <i>interconnector</i> to or from 0 MW to start, stop or reverse its power flow, not arising from a <i>network event, generation event, separation event</i> or part of a multiple <i>contingency event</i> .
Mainland	The Queensland, New South Wales, Victoria and South Australia <i>regions</i>
MASS	<i>Market Ancillary Service Specification</i>
Methodology	AEMO's Inertia Requirements Methodology
ms	millisecond/s
MW	megawatt/s
MWh	megawatt-hour/s
MWs	megawatt-second/s
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NER	National Electricity Rule.
Network event	A credible <i>contingency event</i> other than a <i>generation event, load event, separation event</i> or part of a multiple <i>contingency event</i>
Non-synchronous equipment	Equipment that is not a synchronous production unit or a synchronous condenser
NSCAS	<i>network support and control ancillary service/s</i>
NSP	Network Service Provider
NSW	New South Wales
OEM	original equipment manufacturer
OFGS	<i>over-frequency generation shedding</i>
PSCAD™/EMTDC™	Power System Computer Aided Simulation / Electromagnetic Transient with Direct Current
PSS	<i>power system stabiliser</i>
PSS®E	Power System Simulator for Engineering
pu	per unit
RAS	remedial action scheme
RoCoF	rate of change of <i>frequency</i>
s	second/s
SA	South Australia
Separation event	A credible <i>contingency event</i> affecting a <i>transmission element</i> that results in an <i>island</i>
SMM	single mass model
SSSP	<i>System Strength Service Provider</i>
STATCOM	static compensator

Term	Definition
Synchronous Machine	<i>Synchronous generating units and synchronous condensers</i>
Synthetic inertial response	The emulated inertial response from an inverter-based resource that is inherently initiated in response to a <i>power system</i> disturbance, and sufficiently fast and large enough to help manage RoCoF
TNSP	<i>Transmission Network Service Provider</i>
UFLS	<i>under-frequency load shedding</i>

1.2.2. Interpretation

This Methodology is subject to the principles of interpretation set out in Schedule 2 of the *National Electricity Law*.

1.3. Related documents

Title	Location
System Strength Requirements Methodology	https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf?la=en
NSCAS description and quantity procedure	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/nscas-description-and-quantity-procedure-v2-2.pdf?la=en
Quantifying Synthetic Inertia of a Grid-forming Battery Energy Storage System – Preliminary Report	https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/quantifying-synthetic-inertia-from-gfm-bess.pdf?la=en
Voluntary Specification for Grid-forming Inverters	https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2023/gfm-voluntary-spec.pdf?la=en
Voluntary Specification for Grid-forming Inverters: Core Requirements Test Framework	https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/grid-forming-inverters-jan-2024.pdf?la=en
Inertia in the NEM explained	https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf?la=en
Frequency Operating Standard	https://www.aemc.gov.au/sites/default/files/2024-01/Frequency%20%E2%80%8COperating%20Standard.pdf

1.4. Overview of Methodology

The remaining sections of this Methodology are structured as follows:

- Section 2 provides background information, including the principles that underpin the Methodology.
- Section 3 outlines how *inertia sub-networks* are defined, and the approach for determining the *inertia sub-network islanding risk*.
- Section 4 defines the relevant methodology terminology and sets out the assessment method for calculating the *inertia requirements*.
- Appendix A describes the *inertia network services specification*.

2. Background

2.1. Inertia and related concepts

2.1.1. Inertia definition and inertia support activities

Inertia is defined in the NER² as:

Contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, bidirectional unit, network element or other equipment.

An inertial response is the immediate, inherent, electrical power exchange from a device on the *power system* in response to a *frequency* disturbance. *Power system inertia* is the aggregate equivalent *inertia* of all devices on the *power system* capable of providing an inertial response³.

Inertia support activities are activities approved by AEMO under the NER which adjust the *binding inertia levels* but are not strictly *inertia network services*⁴. These are also discussed in this section as they are important in determining the *inertia requirements* under the NER⁵.

2.1.2. Why inertia is important in the NEM

Historically, the NEM *power system* did not require *Registered Participants* to provide *inertia* because there was always an abundance of *synchronous generating units* online.

A decrease in the proportion of online *synchronous generation* has resulted in a reduction of the *inertia* inherently available to the *power system*.

While it has historically been common to consider *power system inertia* as a global parameter at a system level, the exchange of *active power* involving multiple inertial responses is limited by available *network capacity* for power transfer. During a disturbance, if the distribution of *power system inertia* is concentrated in an area of the *network* with insufficient capacity to carry the resultant power flows out to the rest of the system, the impacts of exceeding transfer limits and other flow-on effects must be considered. This is particularly true for large, sparse *networks* such as the NEM. Consequently, it is critical to ensure a geographically diverse distribution of *power system inertia* across the NEM.

With any loss of transfer capacity for *active power*, for example resulting from a separation event, *inertia* that is not electrically connected⁶ to the alternating current (AC) *power system inertia sub-network* of interest has no effect on that *inertia sub-network*. This means each *inertia sub-network* in the *power system* needs to maintain a minimum level of *power system inertia* in case of total *islanding*.

² NER Chapter 10 Glossary

³ See <https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf?la=en>.

⁴ NER 5.20B.5(a)

⁵ NER 5.20B.2

⁶ As *active power* across direct current (DC) *interconnectors* is controlled, inertial responses across DC connected systems are only possible if the converters of the DC *interconnectors* are designed to provide synthetic inertial response.

2.1.3. Rate of change of frequency (RoCoF)

In a *power system*, *inertia* and *frequency* are closely related. *Power systems* with large *inertia* can resist large changes in *power system frequency* arising from a contingency that leads to an imbalance in supply and demand. Conversely, lower levels of *inertia* increase the susceptibility of the *power system* to rapid changes in *frequency* because of such an imbalance.

Immediately after a *contingency event* that leads to a supply-demand mismatch, *power system frequency* changes. For a very short time following a *contingency event*, the RoCoF largely depends on the *power system* conditions prior to the *contingency event*. Prior to the occurrence of a *contingency event*, the following measures can be taken to reduce post-contingent RoCoF:

- (a) reduce the size of the largest *credible contingency event* by reducing *generation* output, *load* consumption or limiting *interconnector* flow for the relevant credible contingency elements;
- (b) increase the *inertia*; or
- (c) do both (a) and (b).

Limiting RoCoF only increases the time before *frequency* moves outside the normal operating *frequency band*. Table 1 shows the time required for the *frequency* to reach the under-*frequency load shedding* threshold for various RoCoFs.

Table 1 RoCoF and time to reach 49 hertz (Hz)

RoCoF (hertz per second (Hz/s))	Time to reach 49 Hz* (seconds)
4	0.25
2	0.5
1	1
0.5	2

* Starting from 50 Hz.

2.1.4. Frequency control market ancillary services (FCAS)

Inertia by itself cannot arrest a fall in *power system frequency* indefinitely or bring it back to be within the normal operating *frequency band*; it can only reduce the rate at which *frequency* changes. The *power system* needs additional measures to bring *frequency* back within its normal operating *frequency band*. AEMO currently uses Contingency FCAS for this purpose.

Contingency FCAS is a type of *frequency control ancillary service (FCAS)* that helps correct the *frequency* after a *contingency event*. Currently, this service is mainly provided by *synchronous generation* and batteries. *Synchronous generation* uses the speed of the turbine as a proxy for *power system frequency*. There is a close relationship between the speed of a *synchronous machine* and *power system frequency*, but the two quantities are not directly interchangeable when it comes to controls.

One-second (1s) FCAS can help reduce RoCoF, when measured over a 500 milliseconds (ms) window, due to its fast response time. However, it has limited ability to resist RoCoF in the sub-transient timeframe.

2.1.5. Fast frequency response (FFR) and 1-second FCAS

This Methodology uses the term FFR to describe a proportional *frequency* response which ramps quickly enough to assist with keeping the *frequency* nadir inside the *frequency* containment band⁷. Batteries are major providers of FFR because they combine fast IBR ramping with dispatchable headroom. FFR involves an active power change within 1 second. Because FFR can assist with *frequency* containment, it is necessary to consider the availability of FFR when determining the level of inertia required to keep the power system in a satisfactory operating state during interconnected or islanded conditions.

A new very fast (1s) FCAS market commenced on 9 October 2023 which provides a means for procuring FFR⁸. Registered capacity in the 1s FCAS market is quantified in the Market Ancillary Services Specification according to the response provided under a specific test *frequency* ramp, and accounts for both the peak active power change and the total energy delivered⁹. For simplicity, this Methodology quantifies FFR as the full MW headroom available to respond to a *frequency* event, irrespective of the *frequency* conditions required to trigger the full response. Refer to Appendix B for detail on how the units of 1s FCAS are converted into physical headroom.

Additional FFR may be procured by TNSPs outside the 1s FCAS market as an *inertia support activity*.

2.1.6. Remedial action schemes

A fast balance between supply and demand post-contingency can also be achieved by rapidly controlling *generation* or *load*. Depending on the circumstances, this might need to occur considerably faster than any *market ancillary service* if *power system security* is to be maintained in accordance with the NER.

This can be achieved using remedial action schemes (RAS). They can be:

- ‘Event-based’, providing coverage for a small number of specific events (possibly even just one) via dedicated triggering mechanisms, or
- ‘Measurement-based’, providing coverage for a broad range of events based on observable metrics, such as *frequency*, *voltage*, or *power flow*.

2.1.7. Contracting for inertia support activities

Contracting with *Generators* with large *generating units* to reduce their operating levels, thereby reducing the size of the loss of *generation* following a *contingency event*, would reduce the level of *inertia* required to maintain the *power system* in a *secure operating state*. These services can be contracted as *inertia support activities*.

⁷ See Table A.1. and Table A.2 of Frequency Operating Standard at <https://www.aemc.gov.au/sites/default/files/2023-04/FOS%20-%20CLEAN.pdf>.

⁸ The ability for Fast 6s FCAS, Slow 60s FCAS, and Delayed 5m FCAS to contain the *frequency* nadir within the *frequency* excursion band is significantly reduced under low levels of inertia that are the focus of this methodology.

⁹ See section 6.3 of the Market Ancillary Services Specification at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/2024/market-ancillary-services-specification---v82-effective-3-june-2024.pdf.

2.1.8. Synchronous generation

Historically, it was not necessary to consider *inertia* as a necessary service to achieve *power system security*, because there were many *synchronous* generating systems connected to the *power system*, and these provided *inertia* as a matter of course.

Synchronous generation technologies, such as coal, gas and hydro, all operate large spinning turbines and rotors that are synchronised to the *frequency* of the *power system*. They are typically heavy, weighing in the tens and hundreds of tonnes, and naturally provide *inertia* to the *power system*.

When a sudden imbalance between supply and demand occurs, the kinetic energy stored in the rotating mass of the turbine immediately starts to flow into or out of the *power system* to fill the gap in power and restore balance. Hence, *power systems* with large numbers of online *synchronous* generating machines will have a greater ability to resist changes in *power system frequency* than those that do not.

These are devices which provide an *inertia network service*.

2.1.9. Non-synchronous equipment providing an inertial response

Non-synchronous equipment, such as modern wind turbines, solar inverters and batteries, are typically interfaced with the *power system* through electronic devices rather than electro-magnetic coupling, and do not generally supply *inertia* as an inherent characteristic. However, it is possible for some inverter-based resources (IBR) to provide a synthetic inertial response through appropriate designs and controls. This type of response can include a spectrum of services that differ in how they achieve this response.

Synthetic *inertia* is still an emerging area, and industry has not yet reached consensus on its definition. To aid this process, AEMO has *published* a voluntary specification for grid-forming inverters¹⁰.

Under the framework these are tested through the *inertia network services specification* in Appendix A.

2.1.10. Synchronous condensers

Synchronous condensers are rotating machines *synchronously* connected to the *power system*, to provide services such as system strength, *voltage* control and *inertia*. However, they do not have the ability to *generate* or consume¹¹ *active power* beyond their inertial response and therefore do not provide FCAS.

These are devices which provide an *inertia network service*.

¹⁰ AEMO. Voluntary Specification for Grid-forming Inverters, May 2023, at <https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2023/gfm-voluntary-spec.pdf>.

¹¹ Except for consuming a small constant amount of power to keep them rotating.

2.1.11. Loads

There is a significant amount of *inertia* from demand side and distributed energy sources present on the NEM¹². This can come from any induction machine or other device, right down to consumer devices. AEMO acknowledges this, however this inertial contribution will be considered when comparing the amount of *inertia* in the system against the requirements, rather than including it as part of the *inertia requirements*.

2.1.12. Direct current (DC) interconnection

At present no DC *interconnection* in the NEM is able to provide *inertia*, however this may change in the future. It will be considered if this technology is flagged to be deployed in the NEM.

2.2. Relationship between inertia requirements and other documents

2.2.1. Frequency Operating Standard (FOS)

Inertia is measured by reference to AEMO's ability to operate an *inertia sub-network* in a *satisfactory operating state* or a *secure operating state* when the *inertia sub-network* is *islanded*. AEMO must also be able to operate the mainland NEM in a *secure operating state* where no *inertia sub-network* is *islanded*. These parameters depend, among other things, on AEMO's ability to maintain *power system frequency*¹³ within parameters described in the FOS. Whilst *inertia* levels impact other aspects of power system security, maintaining *power system frequency* is the most relevant aspect for determining the *inertia* requirements.

Although referred to as the FOS, there are, in fact, two standards: one for the mainland *regions* and one for Tasmania. The FOS¹⁴ specifies the *frequency bands* and timeframes in which *power system frequency* must be restored following different events but does not set out how *frequency* is to be managed.

A revised FOS became effective in October 2023, and now specifies a maximum RoCoF for a credible contingency event of 1 hertz per second (Hz/s) for the mainland and 3 Hz/s for Tasmania¹⁵.

2.2.2. System strength requirements methodology, system strength requirements and network support and control ancillary services (NSCAS)

In October 2021, the Australian Energy Market Commission (AEMC) changed the previous system strength framework to drive more proactivity in the provision of *system strength services*, deliver a streamlined *connection* process, and leverage economies of scale in larger,

¹² Arena. Reactive Technologies, System Inertia Measurement Demonstration Lessons Learnt Report 2, at <https://arena.gov.au/assets/2024/01/Reactive-System-Inertia-Measurement-Demonstration-Lessons-Learned-Report-2.pdf>.

¹³ NER 4.2.2(a)

¹⁴ AEMC, Frequency Operating Standard, 9 October 2023, at <https://www.aemc.gov.au/sites/default/files/2024-01/Frequency%20E2%80%8COperating%20Standard.pdf>

¹⁵ AEMC, Review of the Frequency Operating Standard 2022, at <https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022>.

centralised investments¹⁶. A new mechanism was also introduced to allow *connection applicants* to decide between procuring their own system strength assets or contributing towards a fleet of centrally provided services.

Each NEM *region's* jurisdictional planning body is the *System Strength Service Provider (SSSP)* in accordance with the NER¹⁷. The SSSP must plan, design, maintain and operate its *transmission network*, or make *system strength services* available to AEMO, to meet NER requirements including to meet the *minimum three phase fault level* and the *efficient level of system strength* in the *system strength standard specification* in accordance with NER S5.1.14¹⁸. The *system strength standard specification* is determined by the *system strength requirements published* by AEMO under the *system strength requirements methodology*¹⁹. AEMO *publishes* a 10-year projection of *system strength requirements* each year.

System strength and *inertia* are related because they can both refer to different aspects of the *power system's* ability to inherently resist a change in the *voltage* waveform. Services that provide one type of service often provide some amount of the other as a byproduct, depending on the design. For example, higher *inertia synchronous* machines tend to have a higher damping factor, which is beneficial for reducing *voltage* oscillations²⁰ associated with low system strength. A certain amount of *inertia* will invariably be available in each *region* because of the implementation of the *system strength requirements*.

Under the Amending Rule, the system strength and *inertia* procurement timeframes have been aligned, to allow for co-optimised security investment. The Amending Rule includes a form of backstop procurement by AEMO in specified circumstances when AEMO declares *inertia* and system strength *shortfalls* through the NSCAS framework within a three-year period²¹.

2.2.3. Power System Model Guidelines

The *Power System Model Guidelines* detail AEMO's requirements for data and models from *connection applicants* and facilitate access to the technical information and modelling data necessary to perform the required analysis.

Submission of accurate models in an appropriate format facilitates a robust analysis of the *power system*, leading to confidence in the assessment and determination of the *inertia requirements*.

2.2.4. General Power System Risk Review (GPSRR)

AEMO undertakes the GPSRR annually for the NEM in consultation with NSPs²². First published in July 2023, the GPSRR replaces the biennial *Power System Frequency Risk Review (PSFRR)*. It includes review and prioritisation of power system risks, events, and conditions that could lead

¹⁶ AEMC, Efficient management of system strength of the *power system*, at <https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system>.

¹⁷ NER 5.20C.3

¹⁸ NER S5.1.14

¹⁹ AEMO, System Strength Requirements Methodology, 1 December 2022 at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf?la=en.

²⁰ See page 30, https://www.transgrid.com.au/media/fo0maqsh/2406-transgrid_meeting-system-strength-requirements-in-nsw-padr.pdf.

²¹ NER 5.20.3(c1) and 5.20.3(c2)

²² AEMO. *General Power System Risk Review*, July 2023, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2023-general-power-system-risk-review/2023-gpsrr.pdf?la=en.

to cascading outages or supply disruptions. This includes the adequacy of emergency *frequency* control schemes such as Under Frequency Load Shedding (UFLS) and, where applicable, Over Frequency Generation Shedding (OFGS) schemes. The GPSRR also draws inputs from, and in turn informs and supports, a number of AEMO's related reports and processes, including the Inertia Report.

For each priority risk, the GPSRR assesses the adequacy of current risk management arrangements. The GPSRR also reviews arrangements for managing existing protected events and considers any necessary changes or revocations.

3. Defining inertia sub-networks and islanding risk

3.1. Inertia sub-network boundaries

NER 5.20B.1(a) requires AEMO to divide the national grid into *inertia sub-networks*.

For the purpose of determining the required levels of *inertia* in the national grid, the connected *transmission* systems forming part of the national grid are to be divided into *inertia sub-networks*. Under clause 5.20B.1(c) of the NER, the boundaries of an *inertia sub-network* must be aligned with the boundaries of a *region* or wholly confined within a *region*.

AEMO may adjust the boundaries of *inertia sub-networks* from time to time, including adjustments that result in new *inertia sub-networks*, in accordance with clause 5.20B.1(b) and the Rules consultation procedures. In making this determination, regard shall be had to the *synchronous connections* between *sub-networks* and adjacent parts of the grid, and the criticality and practicality of satisfying each *inertia sub-network's inertia requirements*.

AEMO confirms that the *inertia sub-networks* remain aligned with *regions*^{23,24}.

3.2. Approach for determining likelihood of inertia sub-network islanding risk

NER clause 5.20.4(d2) requires that this Methodology describe how AEMO determines the likelihood of an *inertia sub-network islanding risk*.

AEMO considers the list of factors from NER 5.20B.2(d) when determining and forecasting the likelihood of a *sub-network islanding*. The list includes matters that AEMO reasonably considers relevant in making its assessment. AEMO considers it is relevant to consider evidence from historical *islanding* events, and the *frequency* or likelihood of specific non-credible events being reclassified as credible in operational timeframes.

AEMO assesses all listed factors for each *inertia sub-network* as part of the annual Inertia Report. On a case by case basis, AEMO may consider additional matters it reasonably considers relevant to the assessment, and will justify these in the annual Inertia Report where applied. AEMO will classify the resulting likelihood of a *sub-network islanding risk* as either 'plausible' or 'not plausible' for the purposes of applying any calculated *sub-network inertia requirements*.

Combined islands

There may be *regions* that are unlikely to *island* individually, due to the number and strength of *connections* they have with adjacent *regions*, but are at risk of forming a combined *island*. As such, in addition to its usual consideration of the likelihood of *inertia sub-networks*

²³ A region in the NEM is an area determined by the Australian Energy Market Commission (AEMC) as being an area served by a particular part of the transmission network containing one or more major load centres or generation centres or both. The current regions in the NEM are largely based on Australian jurisdictional boundaries - New South Wales, Queensland, Tasmania, Victoria and South Australia."

²⁴ NER 11.100.2

islanding individually, AEMO conducts additional *inertia* assessments of cases where two or more *inertia sub-networks* are at risk of forming a combined *island*.

AEMO undertakes a consistent assessment methodology for determining any multi-region *islanding* risks as for the individual *sub-network islanding risks*. For a combined *island*, the *inertia requirement* for the combined *island* will be the highest *binding inertia requirement* for each individual *inertia sub-network*.

Example assessments

Table 2 shows an example of how AEMO presents the results of its *inertia sub-network islanding risk* determination in the Inertia Report. This table is presented as an example only and does not contain comprehensive or accurate assessment of the *regions*.

Table 2 Inertia sub-network islanding risk criteria with New South Wales and South Australia examples

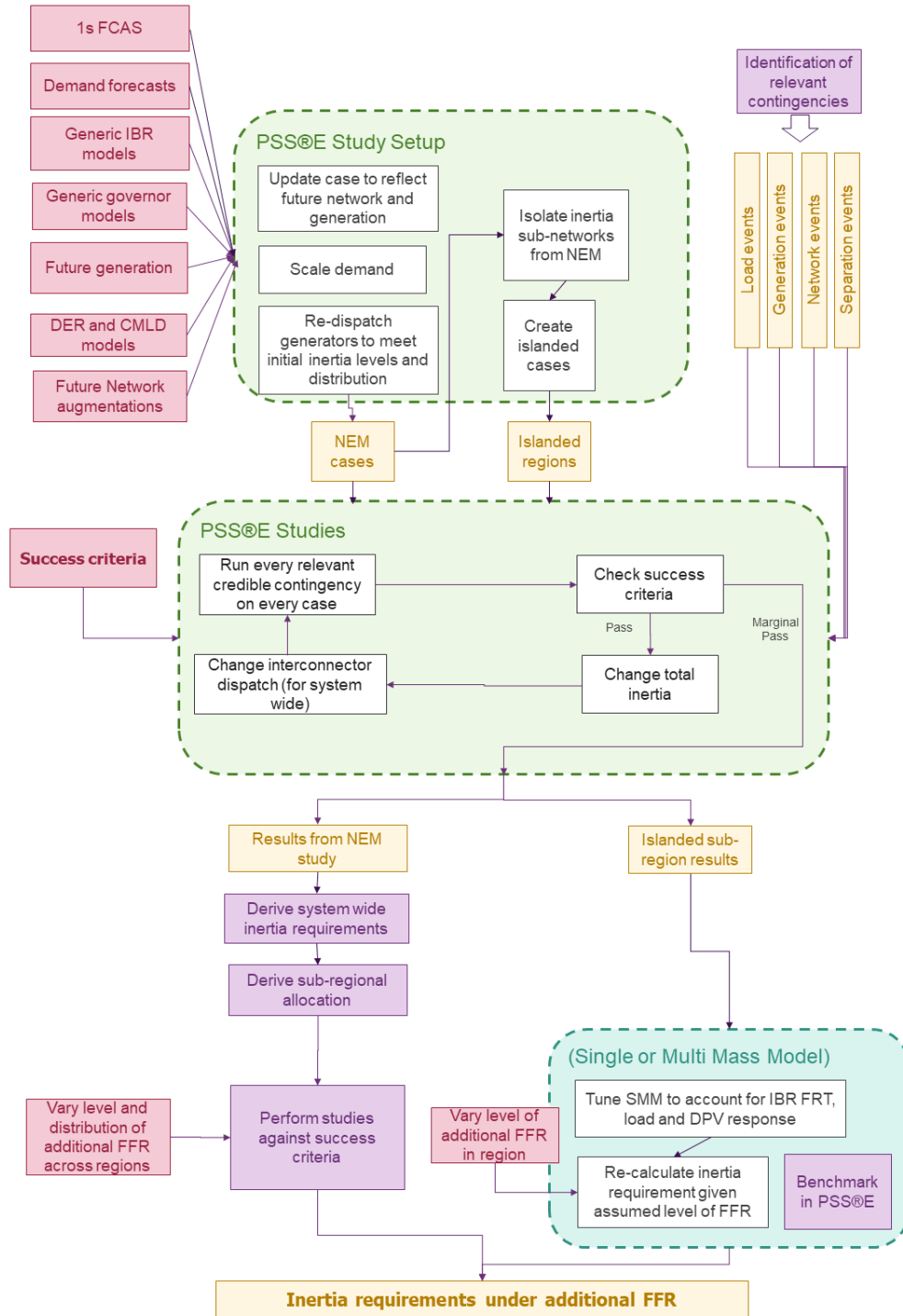
Criterion	New South Wales	South Australia	...
Inertia levels typically provided	12,500 MWs	4,300 MWs	...
Inertia levels compared to secure inertia level	<i>Inertia</i> levels forecast to be above the <i>secure inertia level</i> at all times until FY2029.	<i>Inertia</i> levels forecast to be 2,300 MWs below the <i>secure inertia level</i> 24% of the time in FY2025, which may increase to approximately 53% of the time by FY2029.	
Inertia sub-network allocation (example)	9,000 MWs	1,000 MWs	
Existing interconnections	<ul style="list-style-type: none"> One 220 kV, three 330 kV, and two 132 kV AC <i>connections</i> to Victoria. One 330 kV AC double-circuit and one DC link <i>connection</i> to Queensland. 	<ul style="list-style-type: none"> One 275 kV AC double-circuit to Victoria. One DC link to Victoria. 	
Future interconnections and status	<ul style="list-style-type: none"> PEC: 330 kV double-circuit to South Australia and 220 kV double-circuit to Victoria (Stage 1: 2024, Stage 2: 2027). VNI West: 500 kV double-circuit to Victoria (2029). QNI Connect: 330 kV double circuit to Queensland (2033). 	<ul style="list-style-type: none"> PEC: 330 kV double-circuit to New South Wales (Stage 1: 2024, Stage 2: 2027). 	
History of islanding	N/A	<ul style="list-style-type: none"> November 2022 March 2020 January 2020 November 2019 August 2018 December 2016 September 2016 November 2015 	
Applicable control schemes	TBC	TBC	
Likelihood of islanding after contingency event	Not likely	Plausible until PEC is commissioned	

MWs: megawatt-second/s.

4. Determining inertia requirements

AEMO will determine the *system-wide inertia level*, *satisfactory inertia level* and *secure inertia level* using the approach in this section, to comply with NER clauses 5.20B.2(b)(1), 5.20B.2(b)(3), and 5.20B.2(b)(4). An overview of the approach is provided in Figure 1, followed by detailed descriptions of the various stages.

Figure 1 Overview of approach to determining inertia requirements



4.1. Setting key assumptions, inputs and information

Power system models

The *power system* model is based on a NEM *load* flow case with dynamic information²⁵. This is then updated with changes considered significant and relevant within the next 10 years when calculating the *inertia requirements*, which can include:

- Committed and anticipated *generation*, and *generator* retirement.
- Future *network* development.
- Demand forecasts.
- Latest Composite Load Model (CMLD) and distributed photovoltaics (DPV) models as developed by AEMO²⁶.

Where needed, this can draw on the Integrated System Plan (ISP) and the NEM Electricity Statement of Opportunities (ESOO). AEMO will utilise appropriate generic dynamic models where specific information is not available. This includes in-house generic governor models for *synchronous* machines and best available generic models for IBR, such as the REGC_²⁷.

AEMO will update the PSS[®]E to case to include these updates. AEMO will develop *islanded sub-network* cases by taking *interconnectors* out of service and *re-dispatching generation* within the *region*.

The *binding inertia requirements* are for t+3 years out, and these will only use committed projects unless stated in the Inertia Report.

1s FCAS

The *inertia requirements* are determined considering the amount of available 1s FCAS for each region and the NEM.

AEMO reports on the quantity and type of each market ancillary service that it procures to improve *power system frequency* control outcomes, in accordance with clause 4.8.16(b)(1B) of the NER through quarterly Frequency Monitoring reports²⁸. The amount of FFR procured through the 1s FCAS markets is effectively capped by the raise 6-second (R6) FCAS requirements. The R6 requirements consider steady-state active power changes following a credible contingency including *load* relief, DPV shake off, and the contingency itself.

FFR will be represented in the model by the aggregate headroom of existing and committed BESS with fast *frequency* controllers.

²⁵ Typically, a PSS[®]E case from 'AEMO Modelling Platform'.

²⁶ AEMO. Power system model development, at <https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/power-system-model-development>.

²⁷ EPRI. User Guide for Generic Renewable Energy System Models, at <https://restservice.epri.com/publicdownload/000000003002027129/0/Product>.

²⁸ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-and-time-deviation-monitoring>

4.2. Identifying the most significant credible contingencies

To determine the most significant credible contingency, AEMO will perform *power system* analysis to model the largest RoCoF impact from credible contingencies considering the contingency size, the *inertia* lost as a result of the contingency, the momentary cessation in IBR output due to the *voltage* dip as a result of the contingency, and the *load* response as a result of the contingency. Each of these is detailed below.

Contingency size

This step identifies all relevant *credible contingency events* to be tested in the *power system* simulation studies, which can include events such as:

- **Generation contingency** – typically a large *generator* with high *inertia*.
- **Load contingency** – generally, the largest *load* in an *inertia sub-network* or the NEM would be an industrial *load*, such as a smelter or potline, the size of which is largely uncontrollable via the central *dispatch* process.
- **Separation event** – a credible contingency affecting a *transmission* element that results in an *island*.

Constraint equations that could reasonably be invoked in an *islanded inertia sub-network* or the *power system* to achieve a *secure operating state* will be considered in the maximum contingency size calculation. Examples could be a *constraint* limiting a *generator’s* output to manage the largest contingency in the *island*, or restricting *interconnector* flow when a *region* is at credible risk of separation.

Identifying generation contingency

The loss of a *generating unit* with the highest *inertia* will not necessarily result in the *Generation Contingency* that produces the highest RoCoF in the *inertia sub-network*.

When a *contingency event* results in the loss of a *synchronous generating unit*, the effect is two-fold, in that, along with the loss of *generation*, the *inertia sub-network* also loses the *inertia* associated with that *synchronous generating unit*. Likewise, the DPV and *load* reduction as a result of the fault can impact the largest contingency.

Table 3 shows four different *contingency events* affecting four different *synchronous generating units* and RoCoFs. In this example, the pre-contingent *inertia* and demand in the *inertia sub-network* is 15,000 megawatt-seconds (MWs) and 4,100 MW, respectively.

Table 3 Generation and inertia outcomes

Contingency event number	Contingent inertia (MWs)	Loss of generation (MW)	RoCoF (Hz/s)
1	2,500	150	0.30
2	3,100	150	0.32
3	500	175	0.30
4	3,200	100	0.21

Table 3 demonstrates that the highest loss of *inertia* does not always result in the highest RoCoF, and the largest loss of *generation* does not always result in the highest RoCoF. A contingency that leads to the highest RoCoF is the most onerous contingency.

It is also possible that the most significant contingency will be the trip of a large source of FFR, such as BESS. This will also be considered when identifying the most significant *generation* contingency. AEMO may also consider control schemes that result in the tripping of multiple generators when identifying the most significant credible *generation* contingency.

Identifying the load contingency

This is typically the largest *load* in the *region* which can be disconnected following a credible contingency disconnecting, usually a smelter.

It is also possible that the most significant contingency will be the trip of a large source of FFR, such as BESS. This will also be considered when identifying the most significant credible *load* contingency.

Modelling the DPV and load response

AEMO has developed a CMLD which incorporates both static and dynamic *load* model components. The CMLD provides a more accurate representation of *voltage* and *frequency* responses of different types of *load* and its tripping behaviour, compared to previously used static *load* models²⁹. AEMO has also developed a DPV model which captures the *voltage*, *frequency*, and RoCoF response of DPV, providing an accurate representation of DPV momentary cessation and DPV tripping behaviour.

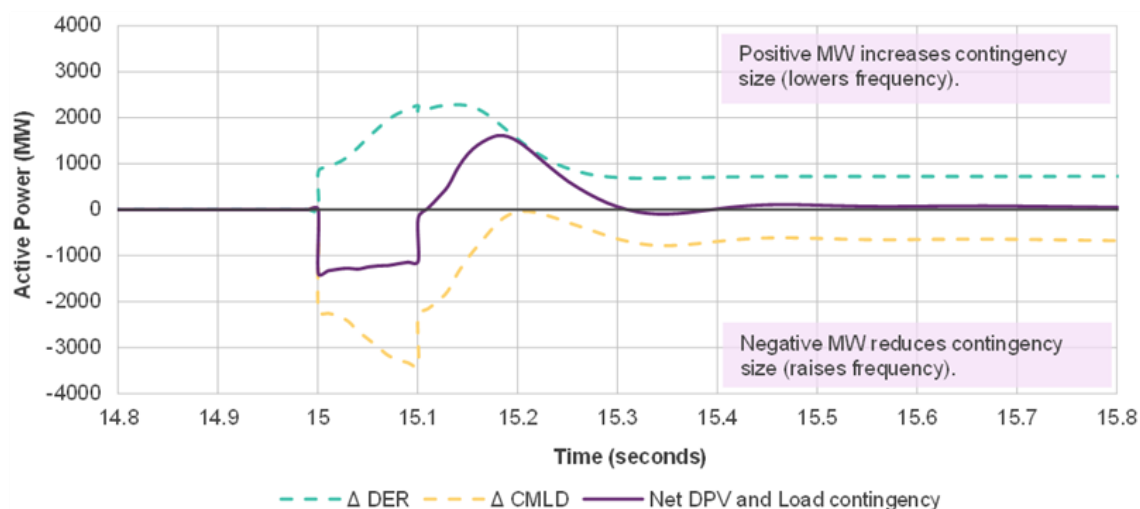
Studies have shown that the accurate modelling of such *load* and DPV behaviours can have significant impacts on *frequency* outcomes. The study results of a Queensland *islanded* case are included below to illustrate the significance of these behaviours. In this example study, the contingency applied is a two phase-to-ground fault at the 275 kilovolts (kV) end of Tarong North Power Station *generator* transformer at 15.0 seconds for 100 ms, followed by a trip of the transformer and Tarong North *generator* which was operating at 180 MW.

Figure 2 below shows the impact of DPV, *load*, and a combination of both on the contingency size. After fault clearance, the slower recovery³⁰ of DPV compared to *load* resulted in an increase in contingency size by approximately 1,500 MW.

²⁹ The CMLD reflects the available inertial contribution from induction motors. This quantity is separate to the inertia requirements, which is reflective of the additional utility scale inertia needed. AEMO will continue to update the CMLD models to reflect the latest available load information.

³⁰ The distributed energy resources (DER) model parameters continuously evolve with the installation of new inverters into the NEM. The parameters used are representative of the study snapshots. In addition, AEMO is undertaking further work to better understand and improve the representation of the transient behaviour of DER and *loads*.

Figure 2 Net load and distributed PV response to Tarong North 180 MW contingency in an islanded Queensland



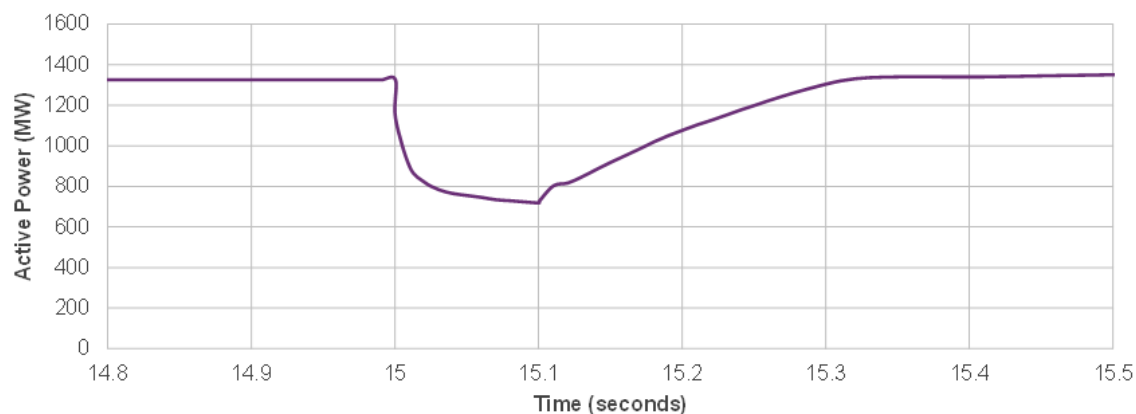
Modelling and quantifying IBR fault ride-through (FRT) response

The installed capacities of large-scale IBR have increased over recent years. During faults, these IBR may enter FRT mode, which involves reducing *active power* output to inject *reactive power* for *voltage* support. The FRT characteristics of large-scale IBR will impact *frequency* outcomes as the reduction in *generation* can be significant.

Figure 3 shows the total solar farm *generation* in the above Queensland study. The total solar farm *active power* output reduced by approximately 46%, which equates to 607 MW.

AEMO uses PSS®E to determine the MW reduction due to fault ride-through. This will be benchmarked against PSCAD™ studies, and any real events, from time to time to ensure accuracy.

Figure 3 Total solar farm generation in a Queensland islanded case under the Tarong North contingency



4.3. Success criteria

The success criteria are conditions that must be met to determine if there is sufficient *inertia*. The success criteria are ultimately derived by taking into account the *inertia requirements* determined under clauses 5.20B.2(b)(1) and 5.20B.2(b)(4), and relevant matters in determining

the *system-wide inertia level* in clause 5.20.4(d1)(1); they can generally be described as the *inertia sub-network*, or the *power system*, being operated continuously in a *secure operating state*.

Specifically, AEMO considers:

- RoCoF and *frequency* requirements specified in the latest version of the FOS are met for all interconnected operating conditions for the system-wide requirements³¹, and for each *region* operating as an *island*³².
- Following any *credible contingency event*, the *power system* or *inertia sub-network* must find a new stable operating point:
 - *Voltages* in the *high voltage transmission network* returned to normal *voltage* ranges.
 - No automatic *load* (UFLS) or *generation* shedding (OFGS) occurred.
 - In-service *transmission* elements remain connected and returned to new steady-state conditions, except for *plant* included in any special control or protection scheme.
 - All in-service *generation* remain connected and returned to new steady-state conditions, except *generators* included in any special control or protection scheme.

4.4. Calculating the secure inertia level and satisfactory inertia level

A *secure power system* must be in a *satisfactory operating state* and be able to return to a *satisfactory operating state* following any *credible contingency* or *protected event* (NER 4.2.4).

Practically, the *satisfactory* limit is the *inertia* required to be online after the specific worst-case contingency, for the *power system* to return to a *satisfactory operating state*. For example, this could be the *secure* operating level of inertia, minus the *inertia* of the largest *generating unit* providing *inertia* within an *inertia sub-network*.

It should be noted that this *satisfactory inertia level* may require limits on *interconnector* flows while the *inertia sub-network* is at a credible risk of separation.

The *satisfactory inertia level* has been defined under NER 5.20B.2(b)(3). One of the indicators of the *power system* being in a *satisfactory operating state* is defined under NER clause 4.2.2(a) as follows:

the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band.

³¹ See Table A.1. and Table A.2 of Frequency Operating Standard at <https://www.aemc.gov.au/sites/default/files/2023-04/FOS%20-%20CLEAN.pdf>.

³² See Table A.5. of Frequency Operating Standard at <https://www.aemc.gov.au/sites/default/files/2023-04/FOS%20-%20CLEAN.pdf>.

4.5. Determining the sub-network inertia requirements

Power system simulation studies will be performed iteratively to assess the performance of an *inertia sub-network* against the success criteria.

Step 1: Apply contingency

This step applies the contingencies identified in section 4.2 to the PSS®E case. For an *islanded inertia sub-network*, this is typically a *load*, or *generator* in the *sub-network*, and the associated response from IBR and *load*.

Step 2: Check success criteria

Check the *power system* performance against success criteria. A description of how *frequency* and RoCoF are measured is in Appendix C.

This will continue until the success criteria are only marginally passed. ‘Marginally passed’ means the removal of a single additional *synchronous* machine being *dispatched* would result in failure to meet the success criteria.

Step 3: Vary the amount of inertia

If the success criteria are passed (or failed), vary the *inertia* in the case by *re-dispatching synchronous* machines as appropriate. Consequently, *load* and/or IBR *generation* output will also need to be varied to ensure supply and demand is balanced. Return to Step 1 and apply the next contingency.

Step 4: Determine the secure inertia level

Once all contingencies have been assessed, the pre-contingent *inertia* amount that results in the success criteria being marginally passed for the most onerous contingency is the *secure inertia level* for the *inertia sub-network*.

4.6. Determining the system-wide inertia requirements

Power system simulation studies will be performed iteratively to assess the performance of each *sub-network* against the success criteria. The initial *inertia* levels and distribution are primarily set by the *secure level of inertia sub-network* values calculated in section 4.5. When setting the initial *inertia* levels, AEMO may also consider the available *inertia* in a *sub-network*, the inertial contributions from adjacent *sub-networks*, the maximum *contingency* size in each *sub-network*, the demand in each *sub-network*, or other relevant considerations that promote balanced procurement of *inertia* across *inertia sub-networks*.

Step 1: Apply contingencies

This step applies the contingencies identified in section 4.2 to the PSS®E case, which can be a *load*, *generator* or *interconnector*. It includes the associated response from IBR and *load*.

For the system-wide requirements, contingencies will be applied in each *sub-network* to ensure the most onerous conditions are studied.

For contingencies which are a fault, the fault clearance times specified in Table S5.1a.2 of the NER will be observed.

Step 2: Check success criteria

Check the *power system* performance against success criteria. A description of how *frequency* and *RoCoF* are measured is in Appendix C.

This will continue until the success criteria are only marginally passed. ‘Marginally passed’ means the removal of a single additional *synchronous* machine being *dispatched* would result in failure to meet the success criteria.

Step 3: Vary the amount of inertia system-wide

If the success criteria are passed (or failed), vary the *inertia* amount in the case by *re-dispatching synchronous* machines as appropriate. The distribution of *inertia* in each *inertia sub-network* is kept the same to the extent possible as the *system-wide inertia level* is decreased.

When varying the *inertia* (by *re-dispatching synchronous generators*), *load* and more *IBR generation* output will be varied to ensure supply and demand is balanced. Return to Step 1 and apply the next contingency.

Step 4: Vary interconnector dispatch

As power flow increases across an *interconnector* following a *contingency event* in a *sub-network*, the amount of ‘headroom’³³ the *interconnector* has is important for the success criteria. AEMO will vary the *interconnector dispatch* to ensure the most plausible, onerous conditions are modelled (effectively reducing the headroom).

Return to Step 1 and apply the next contingency.

AEMO notes that some transient stability/oscillatory stability *constraints* include *inertia* which can limit the *interconnector* flow³⁴. These limits will be observed in the studies.

Step 5: Determine the system-wide inertia level

Once all contingencies have been assessed, the pre-contingent *inertia* amount that marginally passes the success criteria for the most onerous contingency is the *system-wide inertia level*.

4.6.1. Determine the sub-network allocation

When determining the *inertia sub-network* allocation, *NER 5.20B.2(c)* requires that AEMO consider a balanced allocation of the *system-wide inertia level* across the mainland NEM.

When allocating the final system-wide level of *inertia* to each *sub-network*, AEMO will consider the *secure level of inertia* for each *sub-network* when *islanded* (calculated in section 4.5).

AEMO may also consider the available *inertia* in a *sub-network*, the maximum *contingency* size in each *sub-network*, the inertial contributions from adjacent *sub-networks*, the demand in each *sub-network*, or other considerations to promote balanced procurement of *inertia* across *inertia sub-networks*.

³³ Headroom is essentially the overall *interconnector* limit minus the actual *interconnector* flow.

³⁴ An example *constraint* which limits *interconnector* flow as a function of system *inertia* is V::N_NIL_O2. *Inertia* is not the only factor in these *constraints*.

4.7. Assess how increasing amounts of FFR can change the inertia requirements

The *inertia* requirements determined in sections 4.5 and 4.6 are MWs quantities to be met by *inertia* network services. This section explains how AEMO derives a relationship between *inertia* and FFR to quantify how much the *inertia* requirements could be adjusted by procuring FFR *inertia* support activities outside the 1s FCAS market.

It is expected that future BESS projects in the mainland could substantially increase the quantity of FFR that could be contracted for *inertia* support activities.

To derive this relationship for the sub-network *inertia* requirements, a simplified lumped mass model is used to perform multiple simulations where *inertia* is varied. To derive this relationship for the system-wide *inertia* requirements, appropriate power system modelling such as dynamic studies are performed.

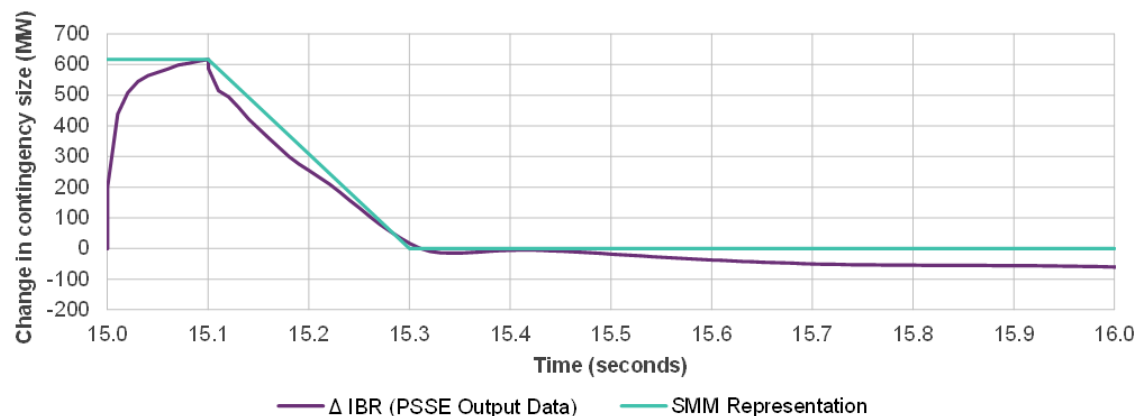
4.7.1. Adjusting the islanded inertia sub-network requirements for FFR quantities

Adjustments to the *islanded sub-network* requirements to account for FFR quantities can be performed using a single mass model (SMM), because the *network (interconnectors)* are not relevant. The SMM represents multiple *generating units* with various *inertia* as a single *generating unit* with equivalent *inertia*, and effectively solves the energy balance of the *power system* over time given the relationship between real power, *frequency* and *inertia*. The SMM is based on the swing equation of the *power system* and iteratively solves a set of equations for *frequency* to model the behaviour of the system.

Tuning the SMM

Given that the SMM does not model concepts such as *network* topology or *voltage*, the output data from the studies in section 4.5 are used to tune the SMM representation to ensure the energy delivered across the first 500 ms after the fault is equal across *power system* simulation software and the SMM. The teal curve in Figure 4 below shows an example of how the IBR FRT response is simplified into a linear representation and modelled in the SMM.

Figure 4 Example IBR fault ride-through representation in SMM

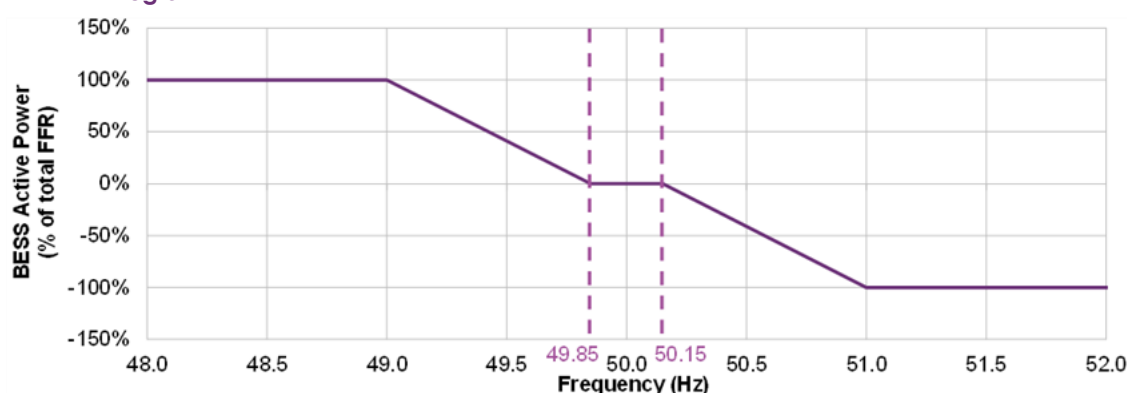


The SMM is tuned by first calculating the areas under the SMM linear graphs and the PSS®E output data for the first 500 ms after the fault. The MW values used in the SMM representation, except for the trip amounts, are then scaled by the ratio *power system studies area*: SMM area until the SMM area matches the *power system studies area*.

BESS response

In the SMM, the BESS provides a *frequency-active power droop*³⁵ response, as shown in Figure 5 below. As *frequency* drops from 49.85 Hz to 49.0 Hz, the BESS *active power* output increases linearly from 0% to 100% of total FFR. Similarly, as *frequency* increases from 50.15 Hz to 51.0 Hz, the BESS *active power* output drops linearly from 0% to -100% of total FFR.

Figure 5 SMM default battery energy storage system droop response in an islanded mainland region



Defining inertia requirements as a function of FFR

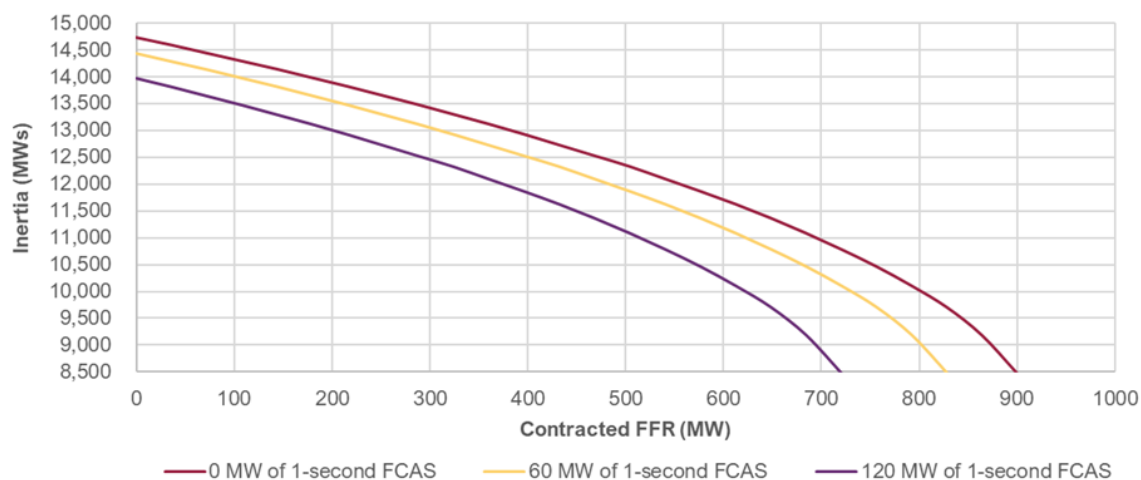
The tuned SMM is used to identify a range of FFR and *inertia* combinations that maintain an acceptable *frequency* response. Figure 6 below provides an example of what the relationship between *inertia* and FFR typically looks like. The curve defines a set of operating points that would deliver a *secure level* of *frequency* control, sufficient to meet RoCoF requirements for all *credible contingency events* in the *region*.

The relationship between *inertia* and FFR is typically non-linear and unique to the system conditions in each *region*. This reflects a spectrum of service response times – acknowledging that *inertia* is uniquely effective at instantaneous *frequency* control, while FFR is able to respond substantially within the first few hundred milliseconds.

The curve divides the space into acceptable and unacceptable *regions* and provides an opportunity for flexible solutions in addressing any declared *shortfalls*. For example, a projected operating point that falls below the curve (*shortfall*), could be returned to the curve (remediated) by moving it up (procuring *inertia*), or right (procuring FFR), or both up and right (procuring both *inertia* and FFR). TNSPs can use this relationship to determine the optimal balance of FFR to reduce the *inertia* requirements, and *inertia* to meet the *inertia* requirements.

³⁵ This droop response reflects the physical response of BESS with *frequency* droop controllers. This response is typically faster than the response which is represented by ideal triangles in the FCAS markets. In addition, these *plants* typically have greater MW capability than their registered raise 1-second (R1) and lower 1-second (L1) FCAS capabilities.

Figure 6 Relationship between inertia and FFR in Queensland from 2023 inertia requirements study



4.7.2. Adjusting the system-wide inertia requirements for FFR quantities

Because the *system-wide inertia requirements* need to consider *network* limitations, such as *interconnector* limits, lumped mass models are more complicated to develop.

AEMO proposes not to develop a lumped model to adjust the system wide level of *inertia* for FFR, and proposes instead to add or remove generic batteries to the model, across all the *regions*, to understand the impact of FFR. *Inertia* will be scaled down approximately evenly across the *regions* (subject to unit sizes). It is expected that *interconnector* limits will be a factor, and *interconnector* limits will be observed as per the relevant *constraint* equations.

The success criteria as outlined in section 4.3 will be used to determine the new *secure level of inertia* at given FFR quantities.

Appendix A. Inertia Network Services Specification

This appendix describes the *inertia network services specification* as required by NER 5.20.4(f), which must include:

- (1) a detailed description of each kind of inertia network service;
- (2) the performance parameters and requirements which must be satisfied in order for a service to qualify as the relevant inertia network service and also when an Inertia Service Provider provides the relevant kind of inertia network service; and
- (3) the process and requirements for AEMO to approve equipment under paragraph (g).

A.1 Description of inertia network services

AEMO describes an *inertia network service* as a service, made available by means of equipment, which provides a contribution to the capability of the *power system* to resist changes in *frequency* by means of an inertial response. This contribution can be made by a *generating unit*, *bidirectional unit*, *network element* or other equipment, whether *synchronous* or non-synchronous.

An inertial response is the immediate, inherent, electrical power exchange from a device on the *power system* in response to a *frequency* disturbance. *Power system inertia* is the aggregate equivalent *inertia* of all devices on the *power system* capable of providing an inertial response³⁶.

A.2 Functional requirements for inertia network services

In accordance with NER 5.20.4(f)(2), AEMO must describe the performance parameters and requirements that must be satisfied by a *plant* to qualify as providing an *inertia network service*, and the conditions under which the *plant* is considered to be providing the *inertia network service*.

A.2.1 Requirements for synchronous plant

The relevant performance parameters for a *synchronous* machine are the mass, spatial distribution, and *synchronous* speed of its rotating components. The *synchronous inertia* of a *synchronous* machine in MWs is the kinetic energy stored at nominal speed which is calculated via

$$\text{inertia (MWs)} = 0.5 J \omega^2$$

where:

- J is the moment of *inertia* in kgm^2
- ω is the nominal speed of rotation in radians per second.

A *synchronous* machine is considered to provide *inertia* whenever it is synchronised with the *power system* at any level of power transfer. The amount of *inertia* provided may vary for some

³⁶ See <https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf?la=en>.

synchronous plant operating in different modes with more or less rotational components connected. For example, a *synchronous generator* with a clutch allowing the prime mover to be disengaged for *synchronous condenser* operation may provide less *inertia* due to loss of the prime mover's mass³⁷.

A.2.2 Requirements for non-synchronous equipment

Non-synchronous equipment covers a broad collection of technologies which may have a wide range of characteristics and parameters relevant to provision of *inertia*, even when considering just different types and manufacturers of IBR *plant*.

The relevant performance parameters and requirements to quantify an inertial response from IBR *plant* is a relatively new, but quickly evolving area, with rapid advancements being made at the time of *publishing*. As such, AEMO does not deem that there is an appropriate set of performance parameters for the provision of *inertia* from non-synchronous equipment, but rather has set out performance requirements which will be assessed on a case-by-case under the testing process outlined in section A.3 for approval under NER 5.20.4(g).

AEMO *publishes* this *inertia network services specification* acknowledging that advancements in technology and understanding may require more regular updates of this Methodology.

AEMO will conduct simulations, as outlined in Section A.3.2, to establish a reference inertia value. Non-synchronous equipment such as IBR *plant* may provide different quantities of *inertia* under different pre-contingent headroom and different size and duration of RoCoF following a *frequency* disturbance. Typically, this difference occurs due to current limits on the device. AEMO acknowledges that the *inertia* provided by non-synchronous equipment may not be a single, constant number.

AEMO will require inertia providers making available *inertia network services* from non-synchronous equipment to specify a reference *inertia* which can be directly referenced against the *inertia requirements* of sections 4.5 and 4.6. The reference *inertia* is the *inertia* provided in response to a 1Hz/s contingency event when operating at the edge of the operational envelope of the device providing the *inertia network service*. AEMO will assess the *reference inertia* for *inertia network services* provided by non-synchronous equipment as part of making an approval under NER 5.20.4(g). Further detail on the range of test conditions AEMO will apply when making an approval under NER 5.20.4(g) is described in section A.3.2.

Important performance requirements for provision of *inertia* from non-synchronous equipment are:

- **Inherency** – the inertial response should be inherent. For the purposes of non-synchronous equipment, this means that it is initiated by the device resisting a change to the *voltage* angle at its point of *connection* that occurs during a change in system *frequency*. The response may or may not then be shaped over a short timeframe by control system action such as primary *frequency* response, FCAS, or action to keep device output within limits.
- **Headroom** – the amount of *inertia* effectively provided will depend on the energy (megawatt hours (MWh)) and capacity (MW) headroom maintained and the conditions of

³⁷ See <https://arena.gov.au/assets/2023/06/repurposing-existing-generators-as-synchronous-condensers-report.pdf>.

the *frequency* disturbance. AEMO has not set specific requirements for maintaining headroom, however, AEMO will discuss with inertia providers an active and reactive power operating envelope within which an *inertia network service* is proposed to be provided when requesting an approval under NER 5.20.4(g). This operating envelope will be used to calculate the *reference inertia* for the *inertia network service*. AEMO expects that any headroom arrangements required to provide an *inertia network service* will be managed by the proponent and relevant *Transmission Network Service Provider* (TNSP) through contracts.

- **Performance at higher RoCoF** - AEMO will assess the *reference inertia* of non-synchronous equipment under 1Hz/s contingencies. However, for higher RoCoF *frequency* disturbances up to 3Hz/s non-synchronous equipment providing an *inertia network service* will still be required to provide *inertia* equal to at least one third of the *reference inertia*. AEMO will use the testing methodology outlined in section A.3.2 to quantify the *inertia* provided at higher RoCoF when making an approval under NER 5.20.4(g).

A.3 Approval process for non-synchronous inertia network services

In accordance with NER 5.20.4(f)(3), AEMO must specify the process and requirements for AEMO to approve non-synchronous equipment under NER 5.20.4(g) to provide *inertia network services*.

A.3.1 Approval request and provision of information to AEMO

Under NER 5.20.4(h), an *Inertia Service Provider* making a request for approval by AEMO under NER 5.20.4(g) must provide the following information to AEMO:

- (1) *details of the proposed equipment by means of which an inertia network service will be made available;*
- (2) *information about how the inertia network services provided by means of the equipment will contribute to the operation of the relevant inertia sub-network in a satisfactory operating state or secure operating state in accordance with the circumstances described in clause 4.4A.3(b)(2) or (3), as applicable; and*
- (3) *any other information requested by AEMO in connection with the request.*

NER 5.20.4(i) gives AEMO discretion to give or withhold approval of equipment, depending on demonstration of the equipment's ability to meet the *inertia network services specification*.

AEMO provides the following guidance regarding the requirements and scope of approval requests made under NER clause 5.20.4(g):

- Appropriate electromagnetic transient (EMT) models must be provided to AEMO, which are high quality (usable, robust and accurate), and in accordance with AEMO requirements³⁸.

³⁸ As defined in AEMO. 2018 Power System Model Guidelines, Final report and determination, June 2018. At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworksreview/2018/power_systems_model_guidelines_published.pdf?la=en&hash=A3DDF450DBEE1E7C1D7E2E379461538A.

- These tests do not test for compliance with requirements under Chapter 5 of the NER, and do not assume that the *plant* can meet existing relevant requirements required to connect to the grid including:
 - Fault ride-through and recovery.
 - *Voltage* control.
 - *Frequency* control.
 - Stability.
 - Operation under partial *load* rejection.
- Additional tests may be requested by AEMO on a case-by-case basis to further demonstrate specific capabilities or to address local concerns depending on the technology under test. These tests are intended to provide a general confidence that the equipment provides the *inertia network service*.
- For clarity, the testing methodology in this *inertia network services specification* will not, in isolation, confirm whether the equipment is compliant with all relevant performance requirements for *interconnection*. Any applicable requirements may also apply under the:
 - NER, and
 - Dynamic Model Acceptance Test (DMAT) Guideline.

An *Inertia Service Provider* can make a request for approval by AEMO via an email submission to planning@aemo.com.au. Given the novel nature of this type of *inertia network service*, AEMO will assess each request on a case-by-case basis. In future it may be possible to move to a templated approach.

A.3.2 Testing methodology

This section details the testing methodology that AEMO will apply when assessing the equipment for the purposes of considering an approval request.

This testing methodology will be limited to simulations only; AEMO will not require Hardware In Loop (HIL) testing when making an approval under NER 5.20.4 (g). Providers of *inertia network services* will be required to undergo commissioning tests and may be required by TNSPs to provide field data to verify expected performance in response to actual events observed in the power system.

AEMO intends for this testing methodology to be independent of the technology providing the *inertia network service*. This methodology will apply to all non-synchronous equipment including IBR sources such as BESS which are likely to be the primary technology to be tested.

AEMO has drawn heavily on *the Quantifying Synthetic Inertia of a Grid-forming Battery Energy Storage System – Preliminary Report*, published by AEMO in September 2024³⁹, and the

³⁹ See <https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/quantifying-synthetic-inertia-from-gfm-bess.pdf?la=en>

Voluntary Simulation Test Framework for Grid Forming Inverters⁴⁰, in developing this testing methodology.

The quantification of an inertial response from IBR *plant* is a relatively new but quickly evolving area, with rapid advancements in technology being made at the time of *publishing*. As such, this *inertia network services specification* may need to be updated regularly. AEMO welcomes working with all stakeholders, including original equipment manufacturers (OEMs) and Network Service Providers (NSPs), more directly if their equipment is under testing to ensure the tests are fit for purpose.

Test to quantify inertia

Under NER 5.20.4(g), AEMO may approve equipment that is not a *synchronous* production unit or *synchronous condenser* for provision of *inertia network services*, if AEMO is satisfied that the equipment will contribute to the operation of the relevant *inertia sub-network* in a *satisfactory* or *secure operating state*⁴¹. This section describes the means by which AEMO will test the contribution of this equipment.

To isolate the inertial response of the equipment under assessment, *frequency* control characteristics such as *frequency* droop control or FCAS enablement will be turned off during testing. Performance in response to a *frequency* disturbance from a clean trip will be used as the primary method to quantify the inertial contribution of equipment under assessment. AEMO will also undertake additional tests to substantiate the inertial response and its robustness.

Conceptual methodology

The measurement of the *inertia* contribution is based on the *power system* swing equation (with damping ignored⁴²), as shown in equation (1)⁴³ below:

$$\frac{2 \times I}{\omega_s} = \frac{P_{mech} - P_{elec}}{d\omega/dt} \quad (1)$$

where

- I is *inertia* in MWs,
- ω_s is *synchronous* speed in radian per second,
- P_{mech} and P_{elec} are the mechanical power into and electrical power out of the *plant(s)* under consideration respectively, both in MW.

Rearranging equation (1), the equivalent *inertia* can be calculated as shown in equation (2) below:

$$I_{total} = \sum_{n=1}^N (MW \cdot s_n) = \frac{\Delta P_{MW} \times f}{2 \times RoCoF} \quad (2)$$

⁴⁰ See <https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/grid-forming-inverters-jan-2024.pdf?la=en&hash=7778A2249D8C29A95A2FADCD9AAA509D>.

⁴¹ In accordance with the circumstances described in NER 4.4A.3(b)(2) or (3), as applicable.

⁴² Note that, unlike *synchronous generators*, depending on the specific implementation, damping may be essential for stable operation of grid-forming BESS, and thus its implication on *inertia* contribution from grid-forming BESS may require further investigations in future. However, the proposed methodology remains practically robust for determining synthetic *inertia* from the system perspective.

⁴³ P.M. Anderson, A. A. Fouad, Power System Control and Stability, 2003, Wiley-IEEE Press, pp. 33-40.

where

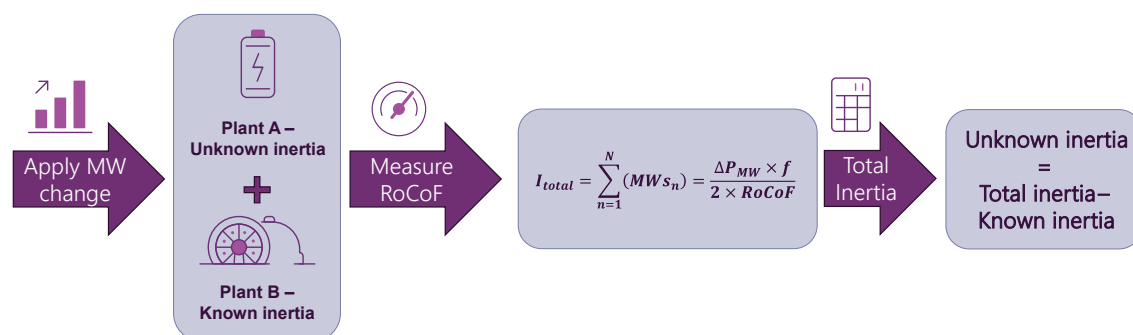
- I_{total} is the total *inertia* contribution of the system in MWs,
- N is the total number of *plants* in the system providing *inertia*,
- ΔP_{MW} is the applied *active power* disturbance to the system in MW,
- f is the nominal *frequency* of the system in Hz,
- $RoCoF$ is the rate of change of *frequency* in hertz per second (Hz/s).

Figure 7 shows a conceptual view of the methodology that has been developed based on the above mathematical representation.

It comprises Plant A (whose inertial contribution is to be determined) and Plant B (whose *inertia* is known⁴⁴). When an *active power* imbalance is applied to the system comprised of Plant A and Plant B, the *frequency* of the system will change. This will result in a RoCoF, which depends on the size of the disturbance and the inertial contribution from Plant A and Plant B. This RoCoF and the known amount of *active power* disturbance is then used to calculate the total *inertia* of the system (comprised of Plant A and Plant B). As the *inertia* of Plant B is known, the *inertia* of Plant A can be determined by subtracting the Plant B *inertia* from the total calculated *inertia*.

It should be noted that this methodology emulates near real-world conditions for providing an inertial response. That is, an *active power* contingency (for example, *load* or *generation* trip) in the system leads to changes in the *frequency*, RoCoF, and *voltage*. Following a contingency, a *plant* capable of providing inertial response will contribute to total system *inertia* in conjunction with other inertial responses in the system. The *frequency* measurement in the *power system* simulation tools can often be complex, and thus utmost care should be taken by user when calculating RoCoF to quantify synthetic *inertia*.

Figure 7 Quantification of inertia contribution steps



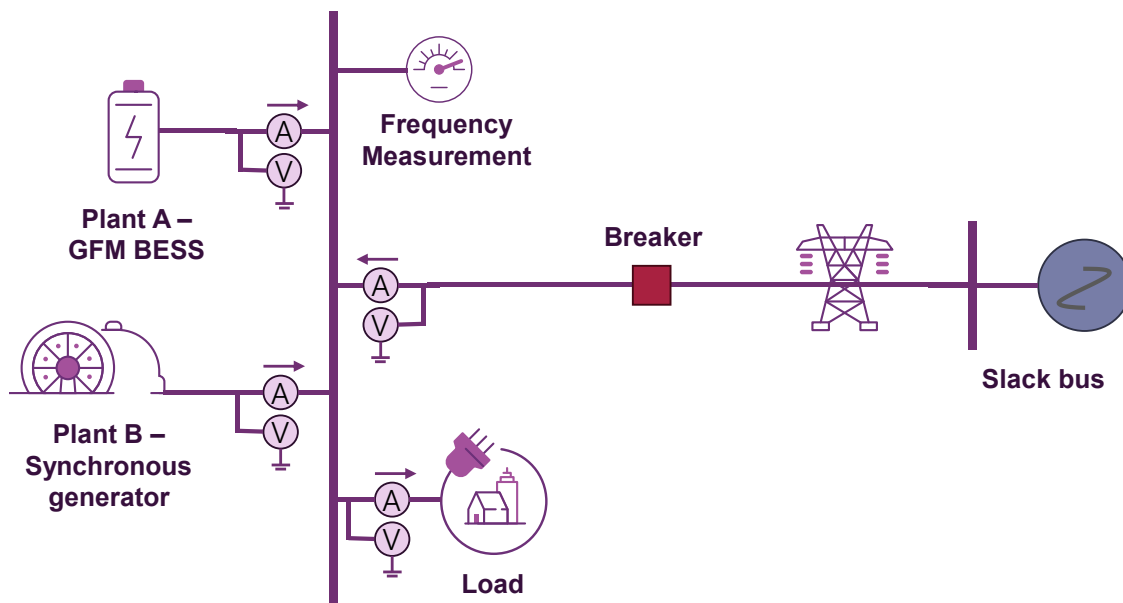
Test system

Figure 8 further illustrates the implementation of the methodology used for this analysis, in an appropriate simulation test setup. A known amount of power imbalance is created by opening the breaker at time of t_0 in the test system of Figure 8.

⁴⁴ This could be a *synchronous generator* whose inertia (MWs) is normally known from the design datasheet or power system model.

Note that depending on the flow across the *transmission line*, the applied contingency would lead to an under-frequency or over-frequency event. Frequency measurement is then used to calculate the RoCoF over a 500ms rolling window. These values will be plugged back into equation (2) for calculation of total inertia (I_{total}). As the inertia from Plant B is already known and tested based on the available data sheet, the unknown inertia of Plant A can be determined by subtracting Plant B inertia from the total calculated inertia.

Figure 8 Schematic representation of the test system using a grid-forming BESS as the plant under test



Test assumptions and inputs

The following assumptions and inputs will be used when applying this test to determine the synthetic inertia from grid-forming BESS:

- Model quality of Plant A should be in accordance with AEMO requirements⁴⁵.
- The inertia of Plant B⁴⁶ will be known.
- Since the ‘bare-bone’ inertial responses of the plants are of interest, frequency control loops of both plants (A and B) will be disabled⁴⁷.
- Load will be constant power and static load (that is, it is not sensitive to voltage and frequency changes).
- The model will meet existing requirements under Schedule 5.2 of the NER.

⁴⁵ AEMO. Power System Modelling Guideline, July 2024, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2023/power_systems_model_guidelines_2023_published.pdf.

⁴⁶ During this work a synchronous machine was used to represent Plant B. It is operating away from any limits (such as Pmin and Pmax) pre- and post-disturbance. Its initial terminal voltage is closer to 1.0 per unit (pu). Although during the work site-specific parameters for automatic voltage control (AVR) and Power System Stabiliser (PSS) have been used, a generic parameter setup is not expected to impact the proposed methodology.

⁴⁷ For a synchronous generator model, the governor should be disabled. For IBR, frequency control response (such as FFR) should be disabled.

- The resultant RoCoF⁴⁸ of the overall system in test will be varied up to 3 Hz/s in each direction⁴⁹.
- Plant B will be approximately twice the size of Plant A to achieve desirable *dispatch*, RoCoF and operating conditions.

Test schedule

A ‘clean’ trip will be used as the primary means to quantify the inertial contribution of the equipment under assessment. This test involves a power imbalance, without a voltage dip associated with the application of a fault. Table 4 provides high-level guidance on the test setup, initial checks, and approach for the simulation. The measured values are then replaced in equation (2) solving for the *inertia* contribution from a grid-forming BESS.

Table 4 Test bench setup in the simulation for primary test – ‘clean’ trip

Initial setup
<ul style="list-style-type: none"> • Set up the simulation case as shown in Figure 8.
<ul style="list-style-type: none"> • If applicable, test the <i>plant</i> under its full range of P and Q outputs.
<ul style="list-style-type: none"> • Set up <i>generation</i> from Plant A, Plant B and <i>load</i> such that desired contingency (<i>active power</i> change) is flowing through the transmission line. <ul style="list-style-type: none"> – This contingency will be varied to result in a RoCoF range from -3 Hz/s to +3 Hz/s.
<ul style="list-style-type: none"> • Disable the control loops in the model which acts on the measurement of <i>frequency</i> and provides <i>frequency</i> control.
Test Sequence ‘clean trip’
1. Run the simulation until a steady state is achieved.
2. Open the breaker at $t = t_0$.
3. Measure the RoCoF* in the system.
Simulation checks
<ul style="list-style-type: none"> • Plants’ <i>active power</i> outputs match desired <i>dispatched</i> levels. • <i>Frequency</i> should initially be 1 per unit (pu). • <i>Voltages</i> across the system is as expected. • There should not be oscillations in the system. • <i>Reactive power</i> output from all devices should be within limits.
Determining <i>inertia</i>
<ul style="list-style-type: none"> • Calculate the total <i>inertia</i> in the system based on the applied contingency and measured RoCoF*. • Subtract the known <i>inertia</i> of Plant B from the total calculated <i>inertia</i> to obtain the <i>inertia</i> contribution from Plant A.

* During this work, a 500 ms rolling window over 2 seconds will be used to calculate RoCoF.

Additional tests to substantiate the inertial response and its robustness

In considering whether to approve equipment under NER 5.20.4(g) AEMO will quantify the *inertia* provided by the equipment under assessment via the procedure outlined above, and undertake additional tests to substantiate the *inertial* response and its robustness. Additional tests will be limited to simulations only, and will include the following:

⁴⁸ Measured over 500 ms window.

⁴⁹ This 3 Hz/s RoCoF value comes from Requirement 9 of Table A2 of the FOS.

(1) Fault response

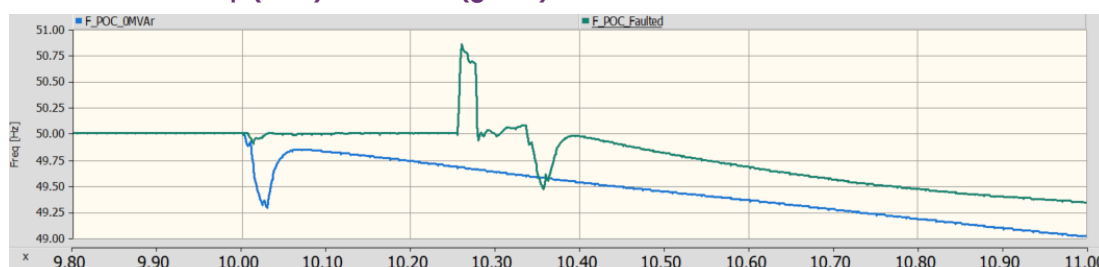
This test will be used to substantiate the robustness of the inertial response provided by the equipment, following the clearance of a *voltage* disturbance which accompanies a *frequency* disturbance. This test involves a 2 phase to ground (2ph-g) fault applied (on the *transmission* system), and then an associated power imbalance because of the fault being cleared. Table 5 provides high-level guidance on the test setup, initial checks, and approach for the simulation. Figure 9 provides example results of equipment providing an inertial contribution for a ‘clean’ trip, with the robustness of the inertial contribution substantiated by the fault response.

Table 5 Test bench setup in the simulation for additional test – ‘fault’

Initial setup
<ul style="list-style-type: none"> Set up the simulation case as shown in Figure 8.
<ul style="list-style-type: none"> If applicable, test the <i>plant</i> under its full range of P and Q outputs.
<ul style="list-style-type: none"> Set up <i>generation</i> from Plant A, Plant B and <i>load</i> such that desired contingency (<i>active power</i> change) is flowing through the <i>transmission line</i>. <ul style="list-style-type: none"> This contingency will be varied to result in a RoCoF range from -3 Hz/s to +3 Hz/s.
<ul style="list-style-type: none"> Disable the control loops in the model which acts on the measurement of <i>frequency</i> and provides <i>frequency</i> control.
Test Sequence fault
1. Run the simulation until a steady state is achieved.
2. Apply 2ph-g fault on the <i>transmission</i> system side of the breaker in Figure 8.
3. Open the breaker to clear the fault according to maximum allowable clearance time in Table S5.1a.2 of the NER and proposed point of <i>connection voltage</i> of the <i>plant</i> under test.
4. Measure the RoCoF* in the system.
Simulation checks
<ul style="list-style-type: none"> Plants’ <i>active power</i> outputs match desired <i>dispatched</i> levels. <i>Frequency</i> should initially be 1 pu. <i>Voltages</i> across the system is as expected. There should not be oscillations in the system. <i>Reactive power</i> output from all devices should be within limits.
Determining inertia
<ul style="list-style-type: none"> Calculate the total <i>inertia</i> in the system based on the applied contingency and measured RoCoF*. Subtract the known <i>inertia</i> of Plant B from the total calculated <i>inertia</i> to obtain the <i>inertia</i> contribution from Plant A. Compare to the results obtained from the primary test

* During this work, a 500 ms rolling window from the time of fault clearance, over 2 seconds will be used to calculate RoCoF.

Figure 9 Example results of non-synchronous equipment provide an inertial contribution for a ‘clean’ trip (blue) and a fault (green)



(2) Angle step change response

AEMO will also validate that the equipment is providing an inertial response, in particular that the response is inherent, as described in section A.2.2. For a non-synchronous machine, a response is considered to be inherent if it is initiated by the equipment under assessment resisting a change to the *voltage* angle at its point of *connection*. To test the response of the equipment to a change in *voltage* angle, AEMO will draw on Test 7 of the Voluntary Specification for Grid Forming Inverters: Core Requirements Test Framework if the plant being tested is an IBR.

Appendix B. 1-second FCAS translation into FFR capability

Services provided by 1s FCAS markets have been included in the modelling approach in this Methodology, however it is important to understand that for BESS providing 1s FCAS, there is a definitional distinction between their total FFR capability and the MW capacity registered in the 1s FCAS market.

FFR capability represents the total physical response available from the *plant* to respond to a *frequency* event due to its nameplate capacity and control systems, typically a *frequency* droop controller. Different *frequency* nadirs may be required to trigger the total physical response depending on the control settings.

In contrast, registered 1s FCAS capacity is quantified in the *Market Ancillary Services Specification* according to the response provided under a specific test *frequency* ramp, and accounts for both the peak active power change and the total energy delivered⁵⁰.

Peak *active power* change is a term defined in the *Market Ancillary Service Specification* (MASS), being the change in power due to its droop setting at the lower or raise reference *frequency*⁵¹. For a typical droop setting of 1.7%, this works out as a 1s FCAS capacity of about 57% of FFR capability⁵².

Essentially, if the *frequency* continues to fall below 49.5 Hz, the battery will continue to increase its output until it reaches the limit set by its droop characteristic, typically at or above 49 Hz.

Because of this difference, the methodology has defined the *inertia requirements* in terms of FFR capability, rather than 1s FCAS capacity. There needs to be a translation between the two to accurately account for how much FFR capability results from the 1s FCAS registration. This translation will continue to be evaluated as the 1s FCAS market behaviour becomes more understood, including how much headroom can be expected from 1-second FCAS providers, and any change to droop settings.

This translation between 1s FCAS capacity and contracted FFR capability does not apply to switched controllers, as these do not implement a droop control response. Switched controllers must switch all the *load* off before *frequency* reaches 49.5 Hz, and do not increase response further as *frequency* falls further towards 49 Hz, so the translation between 1s FCAS capacity and contracted FFR capability is 1 to 1 for these technologies.

⁵⁰ See section 6.3 of the Market Ancillary Services Specification at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/2024/market-ancillary-services-specification---v82-effective-3-june-2024.pdf.

⁵¹ Lower reference *frequency* and raise reference *frequency* are 50.5 Hz and 49.5 Hz respectively (for NEM mainland).

⁵² For more info, see Battery Energy Storage System guide to Contingency FCAS – Version 8, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Battery-Energy-Storage-System-requirements-for-contingency-FCAS-registration.pdf.

B.1 Worked example

A *region* with the following 1-second FCAS registrations has approximately 94 MW of FFR capability:

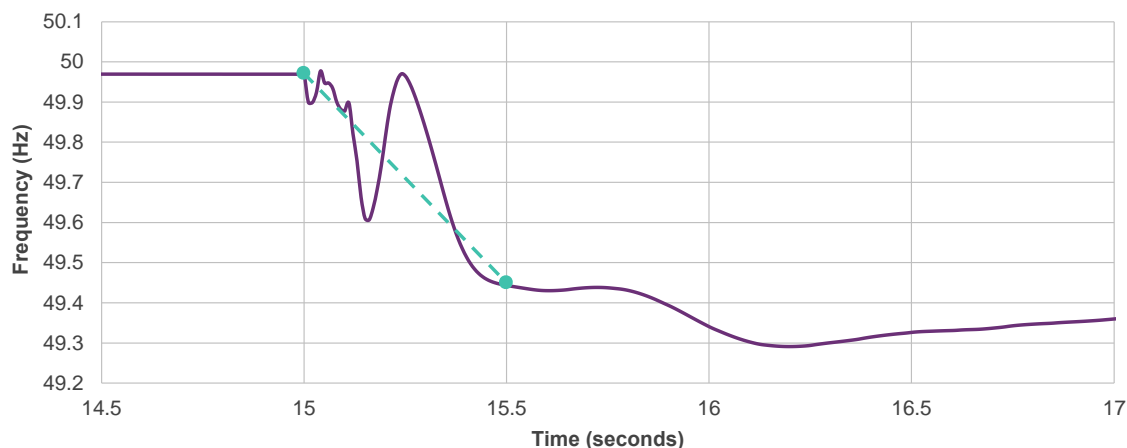
Table 6 Worked example of translating FFR to 1s FCAS

Station name	Bid type	Registered max cap (MW)	Controller	Calculated FFR
BESS 1	Raise1sec	40	Droop (1.7%)	$40/0.57 = 72$
Switched <i>Load A</i>	Raise1sec	10	Switched	10
Switched <i>Load B</i>	Raise1sec	12	Switched	12
			Total FFR	94

Appendix C. Frequency and RoCoF calculations

C.1 Rate of change of frequency measurement over 500 ms period

Figure 10 Measuring RoCoF



C.2 Measuring frequency and RoCoF

Frequency and RoCoF for each *inertia sub-network* are measured by averaging the *frequency* at all buses with a *voltage* greater than or equal to 275 kV in each *inertia sub-network*, and short-term transients are disregarded⁵³. This ‘low pass filter’⁵⁴ approach can be seen in Figure 10. Generally, the highest RoCoF is expected to occur following *contingency events* during low demand periods with low *synchronous generation dispatch*.

⁵³ The 220 kV buses will be used to measure frequency and RoCoF for Tasmania, as this is the highest bus *voltage* for the region.

⁵⁴ This straight line approach mimics the low pass filtering approach which protection relays perform, without creating unnecessary complications by trying to mimic the exact filtering approaches used by different OEMs.

Version release history

Version	Effective date	Summary of changes
2.0	1 December 2024	<p>Revised for the <i>National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 No. 9</i>, accounting for changes to the National Electricity Rules inertia framework, including the following amendments to the Inertia Requirements Methodology:</p> <ul style="list-style-type: none"> • A NEM-wide inertia floor for interconnected operation; and • Removed restrictions on the procurement of synthetic inertia.
1.0	1 July 2018	First issue