INERTIA REQUIREMENTS METHODOLOGY

INERTIA REQUIREMENTS & SHORTFALLS

PREPARED BY: Operational Analysis and Engineering, AEMO

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EXECUTIVE SUMMARY

Power systems with high *inertia* can resist large changes in the *power system frequency* arising from *contingency events* that lead to an imbalance in supply and demand.

At present, AEMO does not *dispatch inertia*. Instead, AEMO uses *constraint* equations to limit the rate of change of *power system frequency* in vulnerable *regions* by controlling *interconnector* flows. This measure will remain in place after the commencement of the National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017 No. 9 (**Inertia Rule**). The Inertia Rule establishes a framework for the management of *inertia*. From 1 July 2018, TNSPs that are *Inertia Service Providers* will have an obligation to provide *inertia network services.*

AEMO is now required to calculate the *inertia requirements* for each *inertia sub-network* in accordance with the *inertia requirements methodology*. The *inertia requirements* are specified as:

- the *minimum threshold level of inertia*, being the minimum level of *inertia* required to operate an *inertia sub-network* in a *satisfactory operating state* when the *inertia sub-network* is *islanded*; and
- the *secure operating level of inertia*, being the minimum level of *inertia* required to operate an *inertia sub-network* in a *secure operating state* when the *inertia sub-network* is *islanded.*

Upon determining the *inertia requirements* for each *inertia sub-network*, AEMO is required to determine whether there are any *inertia shorfalls* in each *inertia sub-network*.

Inertia sub-networks

Under clause 11.100.2 of the NER, the *regions* are the initial *inertia sub-networks.*

Minimum and secure level of inertia

AEMO has calculated the *minimum threshold level of inertia* and *secure operating level of inertia* for each *region* when *islanded*. In determining the required level of *inertia*, AEMO has considered the following factors to reduce the level of *inertia* otherwise needed:

- The largest *credible contingency event* when a *region* is operating as an *island*.
- The level of Contingency FCAS available in each *region.*

2018 Inertia shortfalls

Using the methodology detailed in this document to calculate the *inertia requirements* and determining the *inertia shortfalls*, AEMO has not identified any *inertia shortfalls* for 2018.

CONTENTS

TABLES

FIGURES

1. INTRODUCTION

1.1. Purpose and scope

AEMO *publishes* in this document the:

(a) *inertia requirements methodology* determined under clause 11.100.3(a) of the National Electricity Rules (**NER**) (**Methodology**); and

(b) *inertia requirements* and *inertia shortfalls* determined under clause 11.100.4(a) of the NER.

This Methodology, the *inertia requirements* and *inertia shortfalls* have effect only for the purposes set out in the NER. The NER and the *National Electricity Law* prevail over this Methodology to the extent of any inconsistency.

1.2. Definitions and interpretation

1.2.1. Glossary

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

Terms defined in the *National Electricity Law* and the NER have the same meanings in this Methodology unless otherwise specified.

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.

Term	Definition
Acceptable Frequency	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*.
Contingency FCAS	Each of the following: • *fast raise service*; • *fast lower service*; • *slow raise service*; • *slow lower service*; • *delayed raise service*; and • *delayed lower service*.
EMT	Electromagnetic transient.
EMTDC	Electromagnetic transients, including Direct Current.
Fault Levels Rule	National Electricity Amendment (Managing power system fault levels) Rule 2017 No.10.
Fast FCAS	*Fast raise service* and *fast lower service.*
FCAS	*Frequency* control *ancillary services.*
FFR	Fast *frequency* response.
FRT	Fault ride-through
Generation Contingency	As defined in section 11.2
Inertia Rule	National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017 No. 9.[1]
Load Contingency	As defined in section 11.2
MASS	*Market ancillary service specification*.
Minimum Operating Level	As defined in clause S5.2.5.11 of the NER.
MW	Megawatt

[1] https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque.

Term	Definition
MWs	Megawatt-second
NER	National Electricity Rules.
NSW	New South Wales.
NTNDP	*National Transmission Development Plan.*
PSCAD™/EMTDC™	Power System Computer Aided Simulation / Electromagnetic Transient with Direct Current.
PSS®E	Power System Simulator for Engineering.
RoCoF	Rate of change of *frequency*.
SA	South Australia.
SMM	Single mass model, an equivalent representation of *generating units* with various *inertia* to a *generating unit* with an equivalent *inertia*. This model represents the swing equation of the *power system.*
SPS	Special protection scheme
SSSP	*System Strength Service Provider*
STATCOM	Static Compensator
Synchronous Machine	*Synchronous generating units* and *synchronous condensors.*
TNSP	*Transmission Network Service Provider.*
Typical Inertia	Level of *inertia* typically available in an *inertia sub-network*, measured in accordance with Section 12.1.

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

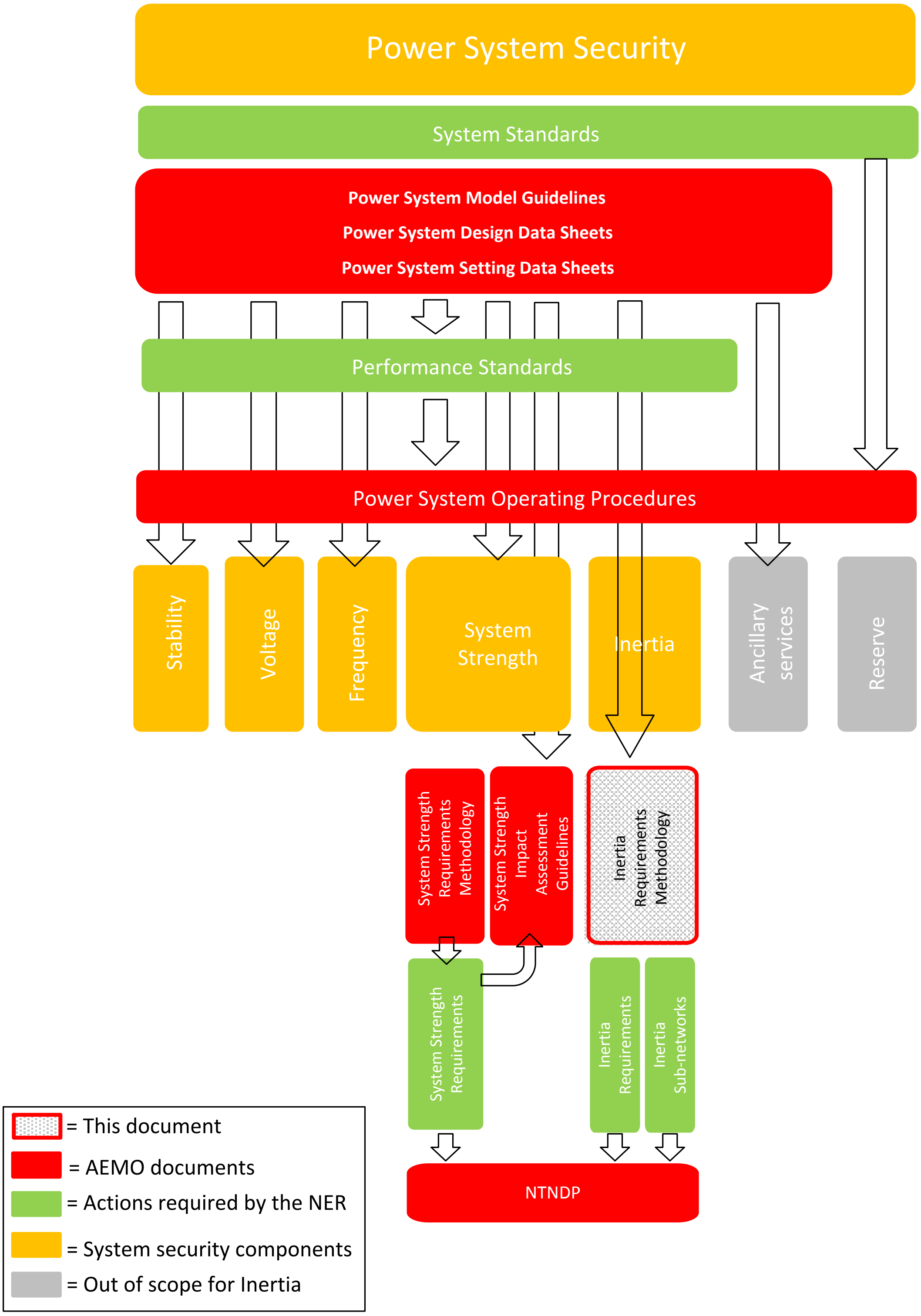
Title	Location
National Transmission and Development Plan	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan
Market Ancillary Service Specification	http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Market-ancillary-services-specifications-and-FCAS-verification

2. CONTEXT

This Methodology specifies the process AEMO has used to determine the *inertia requirements* for each *inertia sub-network* for 2018 and the process it intends to use for 2019 and beyond.

Figure 1 shows the interrelationship between this document and other NER instruments and AEMO guidelines, operating procedures and activities. By no means a complete depiction, it highlights how this Methodology fits in with a number of existing and new requirements on AEMO's ability to meet its *power system security* responsibilities.

Figure 1 Interrelationship of inertia framework components with other power system security requirements



2.1. Relationship with other processes and documents

2.1.1. Frequency Operating Standard

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*. Both of these parameters depend, among other things, on AEMO's ability to maintain *power system frequency* within certain parameters[2].

Although referred to as the *frequency operating standard*, there are, in fact, two standards, one for the mainland *regions* and one for Tasmania.

The *frequency operating standard*[3] 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.

2.1.2. System Strength Requirement Methodology and System Strength Requirements

From 1 July 2018, the National Electricity Amendment (Managing power system fault levels) Rule 2017 No.10[4] (**Fault Levels Rule**) creates a framework in the NER for the management of system strength in the *NEM.*

The Fault Levels Rule prescribes the process AEMO must follow to determine the base level of system strength in each *region*, called the *system strength requirements*, by reference to the *three phase fault level* at *fault level nodes* within each *region*. The *minimum fault levels* at these *fault level nodes* become a proxy for determining how much system strength is necessary for the *power system* to be maintained in a *secure operating state*.

Where a *fault level shortfall* exists, TNSPs will be required to procure *system strength services* to maintain the *minimum fault levels*[5] and *Generators* and MNSPs will be required to contribute towards the maintenance of system strength to the extent that their new or modified *connections* have an *adverse system strength impact*[6].

AEMO will use the *system strength requirements methodology* to assess whether a *fault level shortfall* exists, or is likely to exist in the future.

System strength and *inertia* are related because they can both be enhanced by *dispatching* Synchronous Machines. Therefore, there may be a correlation between the *system strength requirements* and *inertia requirements*, as well as any *fault level shortfalls* and *inertia shortfalls*. It should be noted, however, that there are mechanisms to address *inertia shortfalls* that have no impact on system strength, such as under-*frequency load shedding* or FFR.

2.1.3. Power System Model Guidelines

The *Power System Model Guidelines* detail AEMO's requirements for data and models from 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] See clause 4.2.2(a) of the NER.

[3] Available at: https://www.aemc.gov.au/sites/default/files/content/c2716a96-e099-441d-9e46-8ac05d36f5a7/REL0065-The-Frequency-Operating-Standard-stage-one-final-for-publi.pdf.

[4] Available at https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels.

[5] See clause 5.20C.3(b) of the NER.

[6] For further information about the relevance of new *connections* on system strength, see the *system strength impact assessment guidelines*, available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review

3. BACKGROUND

3.1. The concept of inertia

3.1.1. What is inertia?

Inertia is defined in the NER[7] as:

> Contribution to the capability of the *power system* to resist changes in *frequency* by means of an inertial response from a *generating unit*, *network element* or other equipment that is electro-magnetically coupled with the *power system* and *synchronised* to the *frequency* of the *power system*.

3.1.2. Inertia and rate of change of frequency

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 rate of change of frequency (**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 RoCoF:

(a) reduce the size of the *contingency event* by reducing *generation* output, *load* consumption or limiting *interconnector* flow;

(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 49Hz

RoCoF (Hz/s)	Time to reach 49 Hz[8] (seconds)
4	0.25
2	0.5
1	1
0.5	2

The *power system* needs additional measures to bring *frequency* back within its *normal operating frequency band* and AEMO currently uses Contingency FCAS for this purpose. To allow a higher level of RoCoF, faster correction of the imbalance between supply and demand is required. The timeframe of this correction needs to be faster than the *fast raise service* or *fast lower service*.

These types of corrections are often termed 'fast frequency response' (**FFR**). FFR requires accurate and reliable measurements of *frequency*. Time delays associated with the accurate measurement of *frequency* to facilitate an active FFR-type response would require sufficient *inertia* to be online prior to the *contingency events*.

3.1.3. 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.

[7] See the National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017 No. 9, available at: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque.

[8] Starting from 50 Hz.

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*.

Because they spin *synchronously* with the *power system*, they inherently slow down a change in *power system frequency* immediately after an imbalance between supply and demand. 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.

3.1.4. Asynchronous generation

On the other hand, *asynchronous generation* technologies, such as modern wind turbines, solar inverters and batteries, are *connected* to the *power system* via a power electronic interface and do not bring any *inertia* naturally to the *power system* because they are electrically decoupled from the *power system*. Most modern *asynchronous generation* technologies can be designed to provide *frequency* control capability in the same fashion as Synchronous Machines, however, most existing and committed *asynchronous generation* in the *NEM* has not been designed with this capability.

Because of a lack of inherent *inertia,* these technologies are currently limited in their ability to reduce a change in *power system frequency* immediately after an imbalance between supply and demand.

3.1.5. Synchronous condensors

Synchronous condensors are *synchronously connected* to the *power system* and provide *inertia* to the *power system*. However, they do not have ability to provide FCAS, being as important aspect of inertia requirement, as it will assist in bringing the *frequency* back within *normal operating frequency band*.

3.1.6. Why inertia is important in the NEM

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

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

A further characteristic of *inertia* is that it is a global quantity. This means that, across the *NEM*, as long as there are sufficient Synchronous Machines online across all *synchronously interconnected regions*, there will be no shortage of *inertia*. If a *region* separates from the rest of the *NEM* and operates as an *island*, however, that *region* has to rely on locally available *inertia* to maintain security.

4. HOW AEMO ADDRESSES INERTIA

4.1. Prior to commencement of the Inertia Rule

At present, AEMO does not dispatch *inertia*. Instead, AEMO uses *constraint* equations to limit the RoCoF in a vulnerable *region* by controlling *interconnector* flows. This measure will still remain in place after the commencement of the Inertia Rule.

4.2. Following commencement of the Inertia Rule

The Inertia Rule establishes a framework for the management of *inertia*.

From 1 July 2018, TNSPs that are *Inertia Service Providers* will have an obligation to provide *inertia network services*[9] if an *inertia shortfall* has been identified.

5. THE INERTIA RULE

The Inertia Rule imposes several new responsibilities on AEMO. The following are the most pertinent:

- AEMO is required to develop and *publish* an *inertia requirements methodology* to determine the *inertia requirements* for each *inertia sub-network* by 30 June 2018 (clause 11.100.3(a).

[9] Clauses 4.3.4(j) and 5.20B.4(a) of the NER

- Following 1 July 2018, AEMO is required to *publish* an *inertia requirements methodology* annually as part of the *NTNDP* and, using that methodology, to:
  - determine the boundaries of *inertia sub-networks* (clause 5.20.1(a)(3));
  - determine the *inertia requirements* for each *sub-network* (clause 5.20B.2(a));
  - assess any current *inertia shortfall* and forecast any *inertia shortfall* arising within a planning horizon of at least five years (clause 5.20.2(c)(13)).
- If AEMO determines that there is, or likely to be, an *inertia shortfall* in an *inertia sub-network*, AEMO must *publish* that determination and give to the relevant *Inertia Service Provider* a notice of the assessment along with the date by which the *Inertia Service Provider* must ensure the availability of *inertia network services* (clause 5.20B.3(c)).

6. INERTIA SUB-NETWORKS

Under clause 11.100.2 of the NER, the *regions* are the initial *inertia sub-networks*[10].

7. DETERMINING INERTIA REQUIREMENTS

7.1. Defining the inertia requirements

Clause 5.20.B.2(b) of the NER requires AEMO to calculate the *inertia requirements* for each *inertia sub-network* in accordance with the *inertia requirements methodology*. The *inertia requirements* are specified as:

(a) the *minimum threshold level of inertia*, being the minimum level of *inertia* required to operate an *inertia sub-network* in a *satisfactory operating state* when the *inertia sub-network* is *islanded*; and

(b) the *secure operating level of inertia*, being the minimum level of *inertia* required to operate an *inertia sub-network* in a *secure operating state* when the *inertia sub-network* is *islanded.*

7.2. Minimum threshold level of inertia

The *minimum threshold level of inertia* is defined as the minimum level of *inertia* required to operate an *islanded inertia sub-network* in a *satisfactory operating state*[11].

One of the indicators of the *power system* being in a *satisfactory operating state* is that 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*[12] (**Acceptable Frequency**).

Hence, to be in a *satisfactory operating state*, while *islanded*, an *inertia sub-network* must maintain an Acceptable Frequency.

Note that the impact of the loss of *interconnection* causing formation of a viable *island* was not accounted for because the Inertia Rule allows *constraining interconnector* flow down to zero when there is a credible risk of sepration.

7.3. Secure operating level of inertia

The *secure operating level of inertia* is defined as the minimum level of *inertia* required to operate an *islanded inertia sub-network* in a *secure operating state*[13].

The *power system* is defined as being in a *secure operating state* if, in AEMO's reasonable opinion, taking into consideration the appropriate *power system security principles* described in clause 4.2.6, the *power system*:

[10] Future iterations of this Methodology will include AEMO's determination of *inertia sub-networks* as required by clause 5.20B.1(b) of the NER.
[11] Clause 5.20B.2(b)(1) of the NER.
[12] Clause 4.2.2(a) of the NER.
[13] Clause 5.20B.2(b)(2) of the NER.

(a) is in a *satisfactory operating state*; and

(b) will return to a *satisfactory operating state* following the occurrence of any credible *contingency event* or *protected event* in accordance with the *power system security standards*.[14]

Hence, to operate an *islanded inertia sub-network* to a *secure operating level of inertia,* AEMO must be able to return the *islanded inertia sub-network's* operation to a *satisfactory operating state* following a *credible contingency event*.

In a practical sense, the *minimum threshold level of inertia* is the *inertia* required to maintain a *satisfactory operating state* after the loss of the most significant *inertia* or Contingency FCAS (including FFR) source as a result of a *credible contingency event*. Under such circumstances, *power system frequency* must still be within a particular range to maintain the *power system* in a *satisfactory operating state*. This includes being able to maintain operation within the *operational frequency tolerance band* as well as satisfy any RoCoF limits that may apply within a particular *region*. The *minimum threshold level of inertia* and *secure operating level of inertia* are, therefore, inherently linked via whatever *credible contingency event* has the greatest impact on *frequency* control and RoCoF when *islanded*.

8. INERTIA SHORTFALL

8.1. Determining Inertia Shortfall

Once the *inertia requirements* for an *inertia sub-network* have been determined, clause 5.20B.3(a) of the NER requires AEMO to assess:

(1) the level of *inertia* typically provided in the *inertia subnetwork* having regard to typical patterns of *dispatched generation* in *central dispatch*;

(2) whether in *AEMO's* reasonable opinion, there is or is likely to be an *inertia shortfall* in the *inertia sub-network* and *AEMO's* forecast of the period over which the *inertia shortfall* will exist; and

(3) where *AEMO* has previously assessed that there was or was likely to be an *inertia shortfall*, whether in *AEMO's* reasonable opinion that *inertia shortfall* has been or will be remedied.

In making this assessment, AEMO must take into account the following factors:

(1) over what time period and to what extent the *inertia* that is typically provided in the *inertia sub-network* is or is likely to be below the *secure operating level of inertia*;

(2) the levels of *inertia* that are typically provided in adjacent *connected inertia sub-networks* and the likelihood of the *inertia sub-network* becoming *islanded*; and

(3) any other matters that *AEMO* reasonably considers to be relevant in making its assessment.

8.2. Inertia Network Services to address Inertia Shortfall

To address an *inertia shortfall*, TNSPs that are *Inertia Service Providers* will need to provide *inertia network services* under clause 5.20B.4(b) to the *secure operating level of inertia* (as adjusted for *inertia support activities*, but not less than the *minimum threshold level of inertia* as adjusted for *inertia support activities*). Any proposed investments made to provide *inertia network services* are subject to a *regulatory investment test for transmission*[15] as are any proposed *inertia service payments*[16].

8.2.1. Inertia Network Services up to the Minimum Threshold Level of Inertia

The *inertia network services* that qualify to provide inertia up to the *minimum threshold level of inertia* are:

(1) through the installation, commissioning and operation of a *synchronous condensor*; and

(2) those made available to the *Inertia Service Provider* by a *Registered Participant* and provided by means of a *synchronous generating unit* or a *synchronous condensor* under an *inertia services agreement*.[17]

[14] Clause 4.2.4(a) of the NER.
[15] Clause 5.16.3(a)(10).
[16] Clause 5.16.3(a)(9).
[17] Clause 5.20.B.4(d) of the NER.

8.2.2. Inertia Network Services up to the Secure Operating Level of Inertia

The *inertia network services* that qualify to provide *inertia* beyond the *minimum threshold level of inertia* up to the *secure operating level of inertia* are:

(1) the *inertia network services* referred to in Section 8.2.1;

(2) the installation of *network* equipment other than *synchronous condensors*; and

(3) those made available to the *Inertia Service Provider* by a *Registered Participant* under an *inertia services agreement* other than those referred to in Section 8.2.1.[18]

9. INERTIA SUPPORT ACTIVITIES

Inertia support activities are relevant in adjusting the *inertia requirements* where AEMO forecasts an *inertia shortfall*.

Clause 5.20B.5(b) of the NER allows:

> An adjustment to the *minimum threshold level of inertia* or the *secure operating level of inertia* for *inertia support activities* will apply to the level determined by *AEMO* and only where and to the extent that the approved activity is *enabled* and performing in accordance with the conditions of any approval determined by *AEMO*.

Appendix G discusses the relationship between *inertia support activities* and how they can assist in reducing the *inertia requirements* in an *inertia sub-network*.

AEMO will only accept an *inertia support activity* where it is or has been installed and is *enabled* **solely** in the circumstances described in clause 4.4.4(a) and (b) of the NER. This means that any activity using *plant* installed prior to 1 July 2018 that would otherwise be eligible as an *inertia support activity* will not be considered to be an *inertia support activity*.

There are presently three types of *inertia support activities* that AEMO will consider if requested by an *Inertia Service Provider*, outlined below:

9.1. Special protection 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. Special Protection Schemes (**SPS**) or System Integrity Protection Schemes (SIPS) are two mechanisms that can achieve such an outcome. 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', whereby it provides coverage for a broad range of events based on observable metrics, such as *frequency*, *voltage*, power flow etc.

9.2. Frequency control services

9.2.1. Contingency FCAS

Contingency FCAS is a type of *frequency* control *market ancillary service* that helps to correct the *frequency* after a *contingency event.* Currently, this service is mainly provided by *synchronous generation. 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.

9.2.2. Fast Frequency Response (FFR)

FFR services provide a type of *frequency* control service that can inject power or reduce consumption in response to changes in *frequency* in a timeframe that can be shorter than any *market ancillary service*.

[18] Clause 5.20B.4(e) of the NER.

FFR services rely on the accurate measurement of *frequency* to inject or reduce *active power*. *Frequency* at *generation connection points* is measured differently, depending on whether the *generation* is *synchronous* or *asynchronous*.

Asynchronous plant measures *frequency* by other means that provide the potential for superior *frequency* response, but also present technical challenges associated with the accuracy of the measurement of *frequency*[19].

Accuracy and false triggering of FFR devices is currently an issue when attempting to measure *frequency* and RoCoF very quickly after a major *power system* fault because there is a delay associated with the measurement of the *frequency*, a further communication delay between the measuring unit and the device providing FFR support, a further activation delay associated with the device and, finally, its *active power* ramp up/down time.

Nevertheless, existing technologies that can provide FFR services can be delivered within hundreds of milliseconds, which is considerably faster than than the speed with which *market ancillary services* can be delivered. The ability to rapidly and accurately control *active power* within such a short timeframe (post-contingency) can have a significant impact on the RoCoF in the *power system* and the resulting magnitude of *frequency* excursions.

9.3. Network support agreements

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*. Furthermore, if a *generating unit* is unable to withstand a high RoCoF, contracting to not *generate* at certain times would also reduce the level of *inertia* required to maintain the *power system* in a *secure operating state*.

10. THE METHODOLOGY

Clause 5.20.7(a) of the NER requires AEMO to take the following matters into account in determining the *secure operating level of inertia*:

(1) the capabilities and expected response times provided by *generating units* providing *market ancillary services* (other than the *regulating raise service* or *regulating lower service*) in the *inertia sub-network*;

(2) the maximum *load shedding* or *generation shedding* expected to occur on the occurrence of any *credible contingency event* affecting the *inertia sub-network* when the *inertia sub-network* is *islanded*;

(3) additional *inertia* needed to account for the possibility of a reduction in *inertia* if the *contingency event* that occurs is the loss or unavailability of a *synchronous generating unit*, *synchronous condenser* or any other *facility* or service that is material in determining *inertia requirements*;

(4) any *constraints* that could reasonably be applied to the *inertia sub-network* when *islanded* to achieve a *secure operating state* and any *unserved energy* that might result from the *constraints*; and

(5) any other matters as *AEMO* considers appropriate.

Each of these matters is explained further below.

10.1. Fast FCAS

The capabilities and expected response times provided by *market ancillary services* (other than *regulating raise services* or *regulating lower services*) referred to in clause 5.20.7(a)(1), is a reference to Fast FCAS.

As *inertia* is reduced in an *inertia sub-network*, a larger Fast FCAS response is required to maintain an Acceptable Frequency and keep the *inertia sub-network* in a *satisfactory operating state*.

Inertia by itself cannot arrest a fall in *power system frequency* entirely, or bring it back to be within the *normal operating frequency band*; it can only reduce the rate at which *frequency* changes. Fast FCAS, however, can arrest a decline in *frequency*.

[19] Technology Capabilities for Fast Frequency Response, GE report prepared for AEMO. Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/2017-03-10-GE-FFR-Advisory-Report-Final---2017-3-9.pdf

Therefore, it is necessary to consider the availability of Fast FCAS in each *inertia sub-network* when determining the level of *inertia* required to keep the *power system* in a *satisfactory operating state*.

10.2. Maximum RoCoF

In an *inertia sub-network*, the RoCoF needs to be limited to provide sufficient time for the available Fast FCAS to maintain an Acceptable Frequency and keep the *inertia sub-network* in a *satisfactory operating state*. Limiting the RoCoF would provide sufficient time for the FFR services' measuring devices to measure the *frequency* accurately and thereby avoid maloperation during transient spikes in the *power system*. Furthermore, specific RoCoF limits exist for reasons that include preventing sympathetic tripping of *embedded generation* via anti-*islanding* protection, preventing incorrect operation under-*frequency load shedding* schemes (UFLS) or over-*frequency generator shedding* schemes (OFGS), and exceeding RoCoF limits specified in *performance standards*. RoCoF must be maintained to a level that does not negatively impact *power system security* and *reliability*.

10.3. Maximum load or generation shedding

The maximum size of *load shedding* or *generation shedding* expected to occur on the occurrence of any *credible contingency event* affecting an *islanded inertia sub-network* is relevant because more *inertia* is required to manage a larger quantity of *load shedding* or *generation shedding*, with the same availability and response speed of FCAS.

Hence, the size of the *inertia* must be large enough to cover the largest *load shedding* or *generation shedding* likely to occur following a *credible contingency event* in an *inertia sub-network*.

10.4. Additional contingent inertia

Additional *inertia* where a *credible contingency event* results in the loss or unavailability of a *synchronous generating unit*, *synchronous condensor* or any other *facility* or service that is material in determining an *inertia sub-network's inertia requirements* is also a relevant consideration.

This means an *islanded inertia sub-network* should be able to withstand a *credible contingency event* involving the *disconnection* of its largest *generating unit* or *inertia network service*. This could be either:

- the *generating unit* or *inertia network service* providing the largest amount of *inertia*; or
- the *generating unit* with the highest Minimum Operating Level, representing the largest *generation* loss following a *contingency event*.

10.5. Constraints

Constraint equations that could reasonably be invoked in an *islanded inertia sub-network* to achieve a *secure operating state* and any *unserved energy* that might result from the *constraints* referred to in clause 5.20.7(a)(4) could, for example, include one that operates to limit the RoCoF in an *islanded inertia sub-network*.

11. DETERMINING INERTIA REQUIREMENTS

11.1. General Approach

A two-stage approach is proposed as follows:

Stage 1

The first stage acts as a screening process to assess which *inertia sub-networks* are at risk of experiencing *inertia shortfalls*. At present, as the *inertia sub-networks* are the *regions*, this assessment will be carried out on a *regional* basis[20].

[20] As specified in clause 11.100.2 of the NER. For future assessments, AEMO will need to review whether the *inertia sub-networks* need to be adjusted, as required by clause 5.20B.1 of the NER.

This assessment is based on simplified *frequency* trajectory assessments using SMM[21]. These assessments include assumptions about the delivery of Fast FCAS, and the relationship between *inertia* and the availability of Fast FCAS. These assumptions are described further in Section 11.2.

Stage 2

If the Stage 1 screening process indicates that the *inertia* in an *inertia sub-networks* is approaching the *minimum threshold level of inertia*, a second, more detailed assessment will be carried out.

These more detailed assessments require the use of a PSCAD™/EMTDC™model of relevant *power systems,* to allow determining *minimum threshold level* and *secure operating level of inertia* when an *inertia sub-network* becomes *islanded*.

It was not necessary to carry out a Stage 2 analysis fo any *region* other than SA because AEMO did not identify a likelihood of *inertia shortfalls* in any *regions* except SA.

11.2. Methodology to calculate inertia requirements

AEMO will calculate the *inertia requirements* using the following methodology.

11.2.1. Secure operating level of inertia

This section outlines the methodology to calculate the *secure operating level of inertia* for an *inertia sub-network.*

Step 1: Identification of relevant contingencies while islanded

This step identifies the loss of the largest *generating unit/generating system* or *load* as a result of a *credible contingency event* or *protected event* while the *inertia sub-network* is *islanded* as follows:

- **Generation Contingency**: This is the *generating unit/generating system* whose loss produces the highest RoCoF in the *inertia sub-network*. The loss of a *generating unit* with the highest *inertia* will not necessarily result in the Generation Contingency[22] that produces the highest RoCoF in the *inertia sub-network*.
- **Load Contingency**: Generally, the largest *load* in an *inertia sub-network* would be an industrial *load*, such as a smelter or potline, the size of which is largely uncontrollable via the *central dispatch* process.

It is assumed that a *generating unit's* output may reduce to its Minimum Operating Level via the *central dispatch* process under conditions of low *inertia*, or where Fast FCAS is scarce or expensive, and the optimal *dispatch* solution is to reduce the size of the Generation Contingency to the lowest practical level.

Step 2: Relationship between Fast FCAS requirement and Inertia

A *power system* model of the *inertia sub-network* is used to assess the *frequency* trajectory following the *contingency events* identified in Step 1. This model is then used to establish the relationship between *inertia* levels and the required level of Fast FCAS response to maintain an Acceptable Frequency.

In developing this relationship, the following simplifications may be made:

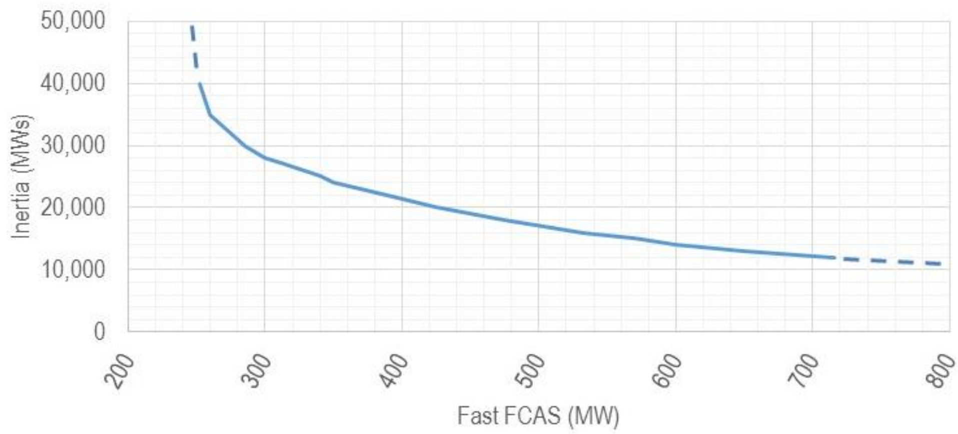
- Generic governor models that represent the MASS requirements[23] of Fast FCAS can be used to develop the inter-relationship between the *inertia* and Fast FCAS requirement.
- A simplified but appropriate wind farm fault ride-through (**FRT**) characteristic can be used.[24]
- With appropriate justification, a simplified SMM of the *power system* can be used.[25]

A *power system* with high *inertia* requires a lower amount of Fast FCAS to maintain an Acceptable Frequency while a *power system* with low *inertia* requires a larger amount of Fast FCAS. For a fixed

[21] A comparision between RMS type analysis and simplified frequency trajectory analysis using SMM is provided in Appendix A.
[22] Refer to Appendix H for an example.
[23] Market Ancillary Services Specification, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Market-ancillary-services-specifications-and-FCAS-verification.
[24] Further details are provided in Appendix E
[25] Refer Table 5 of Appendix A for details.

system demand and contingency size, a typical inverse relationship between Fast FCAS requirement and *inertia* is shown in Figure 2.

Figure 2 Relationship between Fast FCAS requirement and inertia



Step 3: Relationship between Fast FCAS availability and Inertia

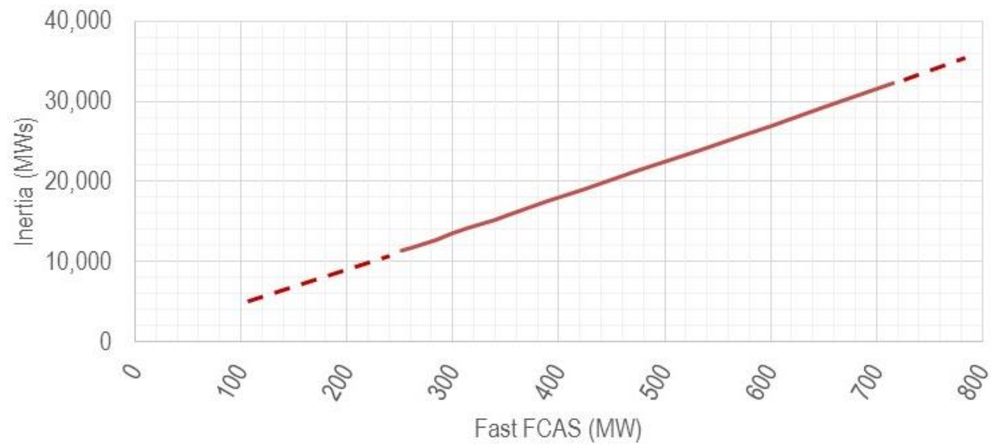
When a *synchronous generating unit* is *dispatched* to provide Fast FCAS[26], it will invariably bring *inertia* to the *power system*. A high availability of Fast FCAS will correspond with high levels of *inertia* in the *power system,* which suggests a correlation between the availability of Fast FCAS, and system *inertia*[27].

Where Fast FCAS is provided by an *ancillary services load*[28], however, it does not bring *inertia* to the *power system*.

The relationship between the amount of Fast FCAS that a *generating unit/load* brings to the *power system* and the *inertia* associated with it will depend on *dispatch* and can be highly variable and unpredictable.

For the purpose of this analysis however, a linear relationship between Fast FCAS availability through *generation* and *inertia* is assumed. This characteristic can be determined for an *inertia sub-network* by assessing the Fast FCAS capability available within that *inertia sub-network*, and the associated *inertia* of *generating units* that provide that capability. An example of such a relationship is shown in Figure 3.[29]

Figure 3 Linear relationship assumed between Fast FCAS availability and inertia



[26] Fast Raise Service or Fast Lower Service.

[27] Currently, the majority of *fast raise services* are provided by *synchronous generating units*. In future, this this correlation might need to be reassessed.

[28] Fast Raise Services.

[29] Fast Raise Services provided by *loads* should been excluded when developing this relationship.

Step 4: Criteria for determining secure operating level of inertia

An operating condition where the amount of *inertia* in an *inertia sub-network* is consistent with both the availability of Fast FCAS, and the Fast FCAS required to maintain an Acceptable Frequency would indicate the *secure operating level of inertia*[30].

The intersection of these two assumed characteristics – the requirement for Fast FCAS, and the availability of Fast FCAS, both as functions of *inertia*, is therefore used to determine the *secure operating level of inertia* for an *inertia sub-network*.

11.2.2. Minimum threshold level of inertia

AEMO operates the *power system* so that, to the extent practicable:

(a) it remains in a *secure operating state*; and

(b) following a *contingency event,* it can return to a *secure operating state*[31].

To be in a *secure operating state*, the *power system* must be in a *satisfactory operating state* and return to a *satisfactory operating state* following the occurrence of a *credible contingency event* or *protected event*[32].

Therefore, when considered through this prism, the *minimum threshold level of inertia* can be calculated as 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 *minimum threshold level of inertia* may require limits on *interconnector* flows while the *inertia sub-network* is at a credible risk of separation.

11.3. Relationship with System Strength Requirements

The Fault Levels Rule requires each *region's System Strength Service Provider* (**SSSP**) to maintain the minimum *three phase fault levels* at each *fault level node* in each *region* (which are determined by AEMO) where the *three phase fault level* typically provided at each *fault level node* by *dispatched generation* is insufficient to maintain the *power system* in a *secure operating state.*

Therefore, a certain amount of *inertia* will invariably be available in each *region* as a result of the implementation of the Fault Levels Rule.

Considering that *system strength services* are required under all operating conditions, as compared with *inertia network services,* which are needed to cater for *islanding* conditions only, AEMO should take into account the typical Synchronous Machine *dispatch* pattern used to calculate *minimum three phase fault levels* at designated *fault level nodes* within an *inertia sub-network* when determining *minimum threshold level of inertia* and the *secure operating level of inertia*.

An assessment of the *inertia* levels as a result from the implementation of the Fault Levels Rule would assist to a large extent in meeting the *inertia requirements* as shown in Table 2. It is noted that in some circumstances, e.g. in NSW, the *inertia* delivered due to the implementation of Fault Level Rule would exceed that required due to the implementation of Inertia Rule.

11.4. Inertia Requirements for 2018

Having used the Methodology outlined in Section 11 to determine the *inertia requirements* for each *region*, Table 2 shows the *inertia requirements* for 2018.

[30] Refer Appendix A for an example.
[31] See clause 4.2.6(a) and (b) of the NER.
[32] See clause 4.2.4(a) of the NER.

Table 2 Inertia requirements for 2018

Inertia sub-networks (Regions)	Inertia available through System Strength (MWs)[33]	Minimum threshold level of inertia (MWs)	Secure operating level of inertia (MWs)
Queensland	11,950	12,800	16,000
New South Wales	18,100	10,000	12,500
Victoria	10,900	12,600	15,400
South Australia	4,900	4,400	6,000
Tasmania	2,000	3,200	3,800

Appendix A to E provide details of the calculations made for each *region*.

12. DETERMINING INERTIA SHORTFALLS

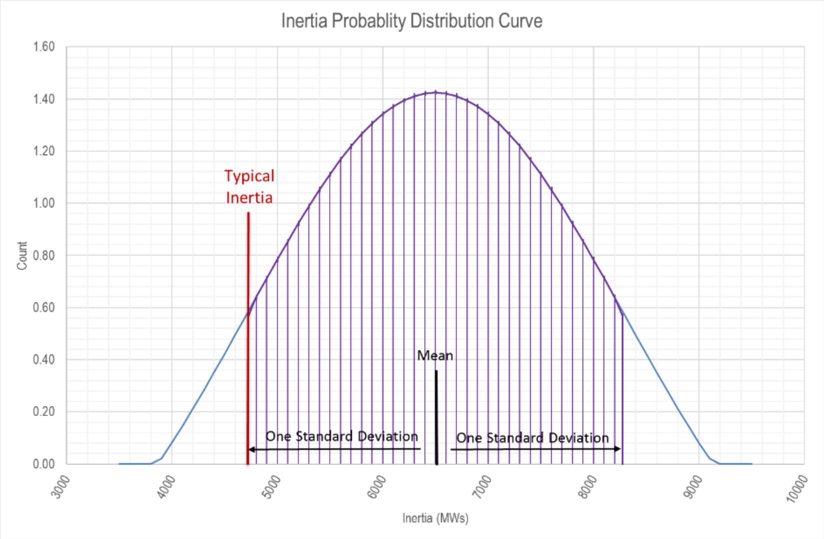
12.1. Typical Inertia

As part of the process of screening for *inertia shortfalls*, AEMO has considered the level of *inertia* typically provided in an *inertia sub-network* by reference to the *dispatched inertia* in that *inertia sub-network* during the previous year[34].

The range of values within one standard deviation of the mean *dispatched inertia* in an *inertia sub-network* during the last year are the levels of *inertia* typically provided in that *inertia sub-network*. Figure 4 shows an example *inertia* probability curve. The shaded area is the range of values within one standard deviation of the mean *inertia*.

For the purposes of calculating an *inertia shortfall*, the Typical Inertia is the Inertia value at one standard deviation below the mean.

Figure 4 Inertia probability distribution curve



This has been chosen because the standard deviation is an accepted statistical method to quantify the variation of a set of data values. Values within one standard deviation of the mean are not at the extremes; they are typical values of the data sets.

AEMO has chosen to use one standard deviation below the mean as this is considered a reasonable onerous scenario. The Typical Inertia for each *region* is provided in Appendix F.

[33] System Strengh Requirements. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review

[34] For Tasmania, the last three years were considered because of the reasons highlighted in Section E.1.

12.2. Inertia shortfall calculation

AEMO calculates the *inertia shortfall* for each *inertia sub-network* as follows:

Inertia shortfall = Typical Inertia – *secure operating level of inertia*

12.3. Interconnection with other inertia sub-networks

In determining whether there are any *inertia shortfalls* in any *inertia sub-network*, clause 5.20B.3(b)(2) of the NER requires AEMO to consider the likelihood of an *inertia sub-network* becoming *islanded*.

AEMO has carried out this analysis and the results are depicted in Table 3:

Table 3 Likelihood of Islanding of each Inertia Sub-Network

Inertia Sub-Network	Interconnections	Likelihood of Islanding
Queensland	One 330 kV AC double-circuit to NSW. One DC link to NSW.[35]	Likely
New South Wales	One 220 kV and three 330 kV AC *connections* to Victoria. [36] One 330 kV AC double-circuit and one DC link *connection* to Queensland.	Unlikely
Victoria	One 220 kV and three 330 kV AC *connections* to NSW. One double-circuit 275 kV AC and one DC link *connection* to SA. One DC link to Tasmania.	Unlikely[37]
Tasmania	One DC link to Victoria.	Likely
South Australia	One 275 kV AC double-circuit to Victoria. One DC link to Victoria.	Likely

13. INERTIA SHORTFALLS

13.1. Inertia Shortfalls for 2018

Using the methodology for calculating the *inertia requirements* outlined in Section 11 and the one for calculating *inertia shortfalls* in Section 12, Table 4 shows the *inertia shortfalls* for 2018. Further details of the rationale for the results for each *inertia sub-network* can be found in Appendices A to E.

Table 4 Inertia shortfalls for 2018

Inertia sub-networks	Typical level of inertia (MWs)	Minimum threshold level of inertia (MWs)	Secure operating level of inertia (MWs)	Inertia shortfalls (MWs)
Queensland	26,800	12,800	16,000	None
New South Wales	32,600	10,000	12,500	None
Victoria	17,100	12,600	15,400	None
South Australia	6,200	4,400	6,000	None
Tasmania	6,000	3,200	3,800	None

13.2. Consideration of Inertia Support Activities

No *Inertia Support Provider* requested AEMO's approval of any *inertia support activities* under clause 5.20B.5(a) of the NER.

[35] Murraylink and Directlink are DC *interconnectors*, therefore they do not provide *synchronous connection* to other *regions*.
[36] The Victoria to NSW *interconnector* also has two 132 kV *connections* that don't form part of the main *transmission* backbone.
[37] Victoria was *islanded* on 16 Jan 2007 as a consequence of multiple *transmission line* trips in quick succession during a bushfire. Since then, AEMO considers a repetition of such an event unlikely because AEMO has commissioned emeregency control scheme which will reduce the risk of islanding significantly.

APPENDIX A. INERTIA REQUIREMENTS FOR QUEENSLAND

Appendix A shows AEMO's calculations of the *inertia requirements* for Queensland using the methodology outlined in Section 11.

A.1 Secure operating level of inertia

Step 1: Identification of relevant contingencies while islanded

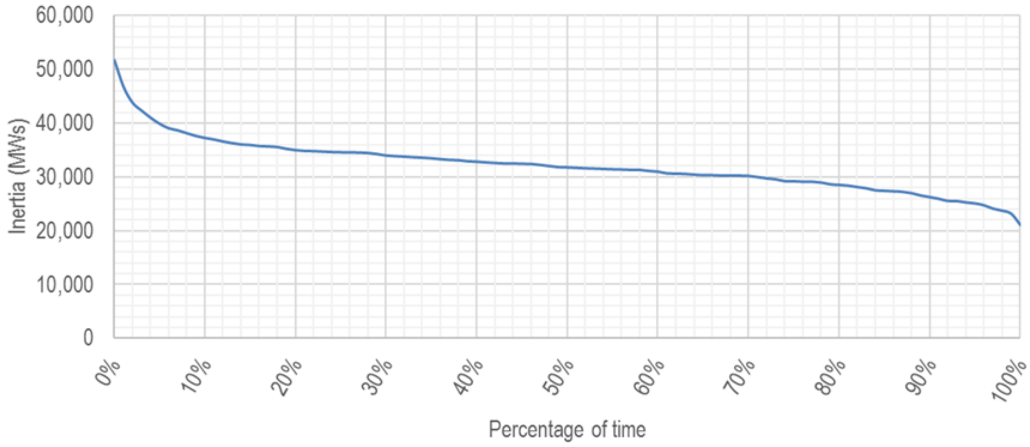
While Queensland is an *island* the following are the largest *credible contingency events* (currently there are no *protected events*):

- **Generation Contingency**: Kogan Creek has the largest *generating unit*, while Swanbank E has the largest *inertia generating unit*. Both can reduce to their respective Minimum Operating Levels. Considering the size of the largest loss of *generation* and *inertia*, Kogan Creek at its Minimum Operating Level was the Generation Contingency utilised.
- **Load Contingency**: The largest loss of *load* following a *contingency event* would be loss of one Boyne Island Smelter potline.

Step 2: Relationship between Fast FCAS and inertia

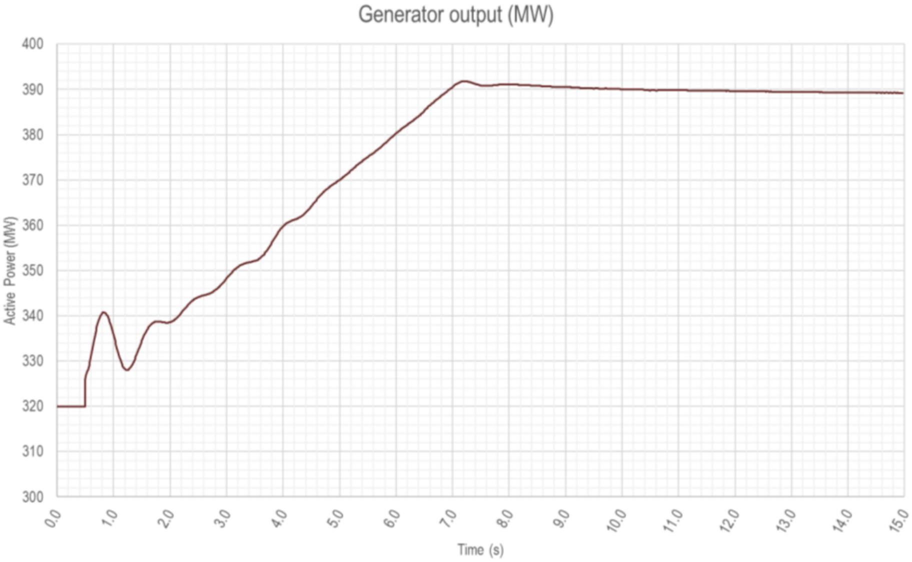
Queensland has a large number of thermal *power stations*. Figure 5 shows the *inertia* duration curve for 2017. The lowest *inertia dispatch* that occurred on 3 October 2017 at 2330 hrs is used for *power system* analysis.

Figure 5 Queensland inertia duration curve



The base case developed was integrated with generic governor models, which simulated a simplified governor response that closely aligned with the MASS requirements for Fast FCAS. One such example is shown in Figure 6.

Figure 6 Generic governor response



Comparison between PSS®E and SMM

After integrating governor models into the base case, the base case was tested for various operating conditions. A comparison between the results achieved using PSS®E and a SMM was carried out.

The insignificant difference in Fast FCAS requirements between two simulation platforms, as shown in Table 5, suggests that an SMM can be used to calculate the *inertia requirements*.

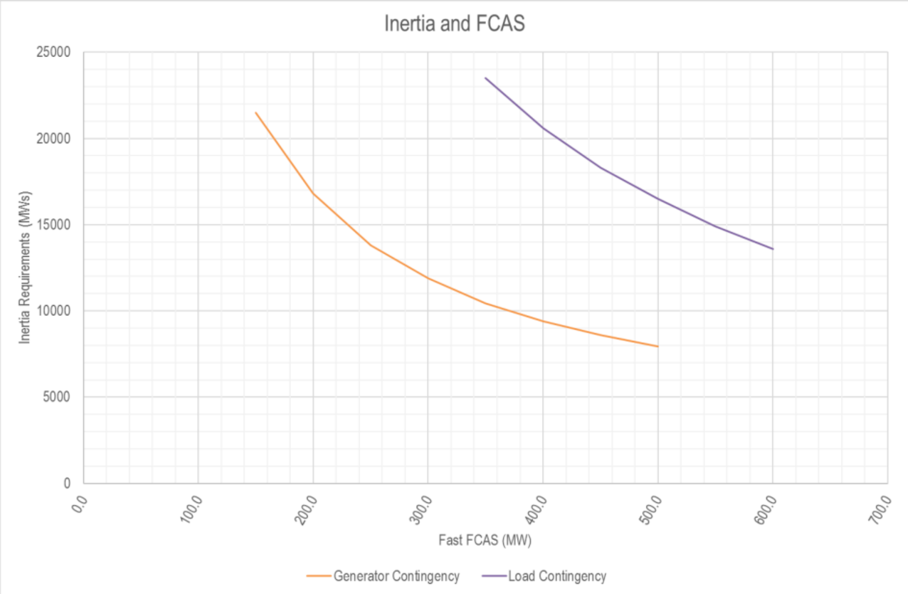
Table 5 Comparison between PSS®E and Single Mass Model

	System conditions					**RMS model**	**SMM**
Sr No	Inertia (MWs)	Demand (MW)	Contingency (MW)	Contingent Inertia (MWs)	Frequency Nadir (Hz)	Fast FCAS requirements in RMS type simulation (MW)	Fast FCAS requirements using SMM (MW)
1	17116	4518	300	2079	49.10	**270**	**285**
2	18246	4693	300	2079	49.05	**230**	**226**
3	20343	5082	300	2079	49.11	**230**	**212**
4	21391	5082	350	1047	49.10	**280**	**296**

Figure 7 shows the relationship between the *inertia* and amount of Fast FCAS required to maintain an Acceptable Frequency[38].

[38] POE 99 demand of the previous year and 1.5% load relief have been used in the analysis.

Figure 7 Relationship between Fast FCAS and inertia



Step 3: Inertia available through Fast FCAS

Queensland has 1,206 MW of *fast raise services* and 688 MW of *fast lower services* available from *synchronous generating units*[39]. *Dispatching* 688 MW of *fast lower services* and 1,206 MW of *fast raise services* would add 21,000 MWs[40] and 24,000 MWs[41] of *inertia,* respectively, considering the combined *inertia* of all Fast FCAS providers in Queensland.

The associated *inertia* for different levels of Fast FCAS in Queensland was calculated, and is displayed in Figure 8.

Step 4: Secure operating level of inertia

Figure 8 shows the relationship between the *inertia* required and Fast FCAS to maintain an Acceptable Frequency for the largest Generation Contingency and Load Contingency, as determined in step 1. It also shows the *inertia* available by *dispatching fast raise services*. The intersection of the two curves indicates the *secure operating level of inertia* for the largest Generation Contingency or Load Contingency, as applicable.

Therefore, the *secure operating level of inertia* is 16,000 MWs[42]. This level of *inertia* would maintain an Acceptable Frequency for the largest Generation Contingency or Load Contingency.

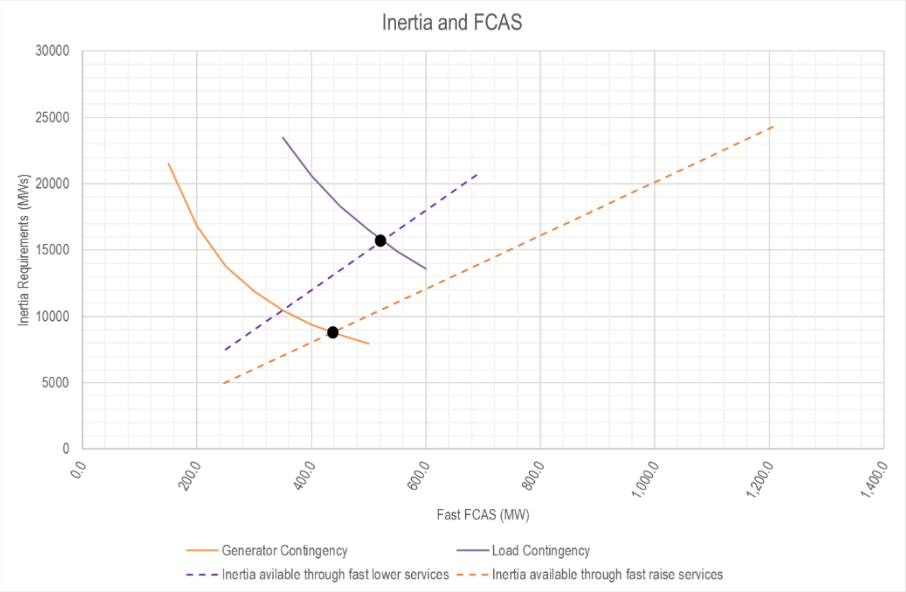
[39] As detailed in AEMO's NEM Registration and Exemption List. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists. The list *published* as at 11 April 2018 was used to complete the analysis to *publish* the *inertia requirements* by 30 June 2018.

[40] Rounded to the nearest 100 MWs.

[41] Rounded to the nearest 100 MWs.

[42] Rounded to the nearest 100 MWs.

Figure 8 Relationship between Fast FCAS and inertia



A.2 Minimum threshold level of inertia

The *minimum threshold level of inertia* is determined by subtracting the largest *inertia generating unit* in Queensland from the *secure level of inertia* just determined.

The largest *inertia generating unit* in Queensland is Swanbank E with 3,225 MWs of *inertia*. Therefore,

Minimum threshold level of inertia = 16,000 MWs – 3,225 MWs = 12,775 MWs

The *minimum threshold level of inertia* for Queensland is 12,800 MWs[43].

[43] Rounded to the nearest 100 MWs.

APPENDIX B. INERTIA REQUIREMENTS FOR NEW SOUTH WALES

Appendix B shows AEMO's calculations of the *inertia requirements* for NSW using the methodology outlined in Section 11.

B.1 Secure operating level of inertia

Step 1: Identification of Relevant Contingencies while Islanded

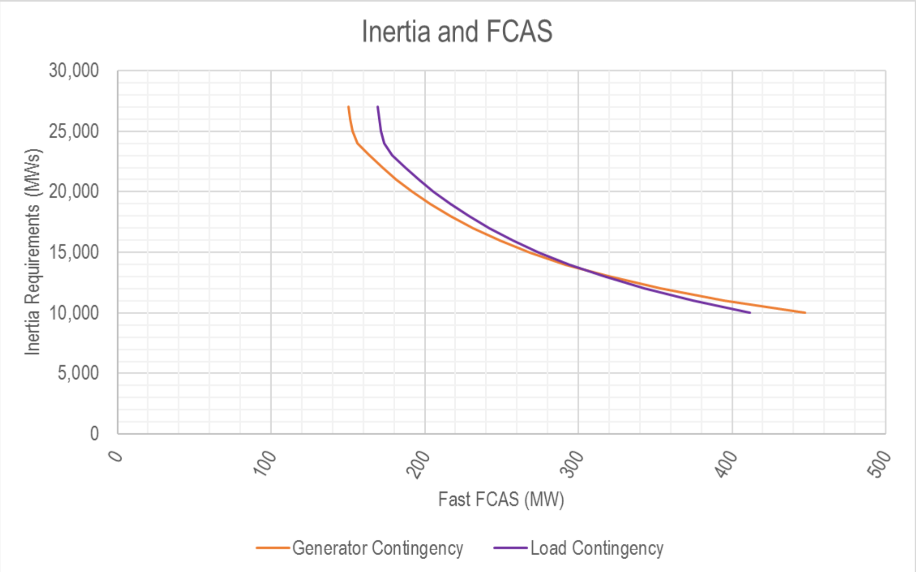
While NSW is an *island* the following are the largest *credible contingency events* (currently there are no *protected events*):

- **Generation Contingency**: Bayswater's *generating units* have the highest Minimum Operating Level (330 MW) of any *generating unit*, but they have a slightly lower *inertia* than Eraring's *generating units* (2483 MWs as opposed to 2516 MWs), however, Eraring *generating units* have a significantly lower Minimum Operating Level (210 MW) so the small *inertia* difference is not considered to be material. Therefore, a Bayswater *generating unit* at its Minimum Operating Level was the Generation Contingency utilised.
- **Load Contingency**: The largest loss of *load* following a *credible contingency event* is the loss of one Tomago potline.

Step 2: Relationship between Fast FCAS and Inertia

Studies for Queensland demonstrated that an SMM can be used to establish a relationship between the level of *inertia* and the amount of Fast FCAS required to maintain an Acceptable Frequency in an *islanded region*. Figure 9 shows this relationship for NSW. [44]

Figure 9 Relationship between Fast FCAS and inertia



Step 3: Inertia available through Fast FCAS

NSW has 1,674 MW of *fast raise services* that can be provided by *synchronous generating units* and *loads* (842 MW by *synchronous generating units* and 832 MW by *loads*). It also has a maximum of 1,184 MW of *fast lower services* that can be provided by *synchronous generating units*.[45] When a *synchronous generating unit* is *dispatched* to provide Fast FCAS it will invariably bring *inertia* to the *power system*. For

[44] This analysis assumed a contingency as determined in Step 1, a POE 99 demand of the previous year and 1.5% load relief.

[45] As detailed in AEMO's NEM Registration and Exemption List. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists. The list *published* as at 11 April 2018 was used to complete the analysis to *publish* the *inertia requirements* by 30 June 2018.

example, *dispatching* 1,674 MW of *fast raise services* or 1,184 MW of *fast lower services* would add 45,000 MWs[46] of *inertia* to the *region*.

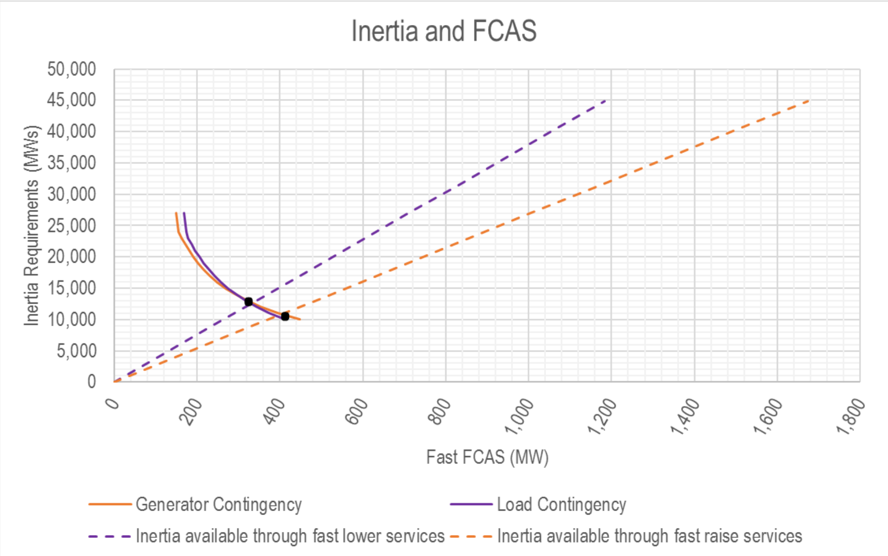
The *inertia* for different levels of Fast FCAS in NSW was calculated, and this is displayed in Figure 10.

Step 4: Secure Operating Level of Inertia

Figure 10 shows curves illustrating the relationship between *inertia* and Fast FCAS required to maintain an Acceptable Frequency for the largest Generation Contingency and Load Contingency, as determined in step 1. It also shows two linearized relationships between Fast FCAS and *inertia* available by *dispatching* Fast FCAS that are relevant for the Generation Contingency and Load Contingency. The intersection of each curve with its relevant line indicates the *secure operating level of inertia* for the largest Generation Contingency or Load Contingency, as applicable .

The highest *secure operating level of inertia* is 12,500 MWs[47]. This level of *inertia* would maintain an Acceptable Frequency for the largest Generation Contingency or Load Contingency.

Figure 10 Relationship between Fast FCAS and Inertia



B.2 Minimum threshold level of inertia

The *generating unit* with the highest *inertia* in NSW is any Eraring *generating unit* with 2,516 MWs of *inertia*. Therefore:

Minimum threshold level of inertia = 12,500 MWs – 2,516 MWs = 9,984 MWs

The *minimum threshold level of inertia* for NSW is 10,000 MWs.[48]

[46] Rounded to the nearest 100 MWs
[47] Rounded to the nearest 100 MWs.
[48] Rounded to the nearest 100 MWs.

APPENDIX C. INERTIA REQUIREMENTS FOR VICTORIA

Appendix C shows AEMO's calculations of the *inertia requirements* for Victoria using the methodology outlined in Section 11.

C.1 Secure operating level of inerita

Step 1: Identification of Relevant Contingencies while Islanded

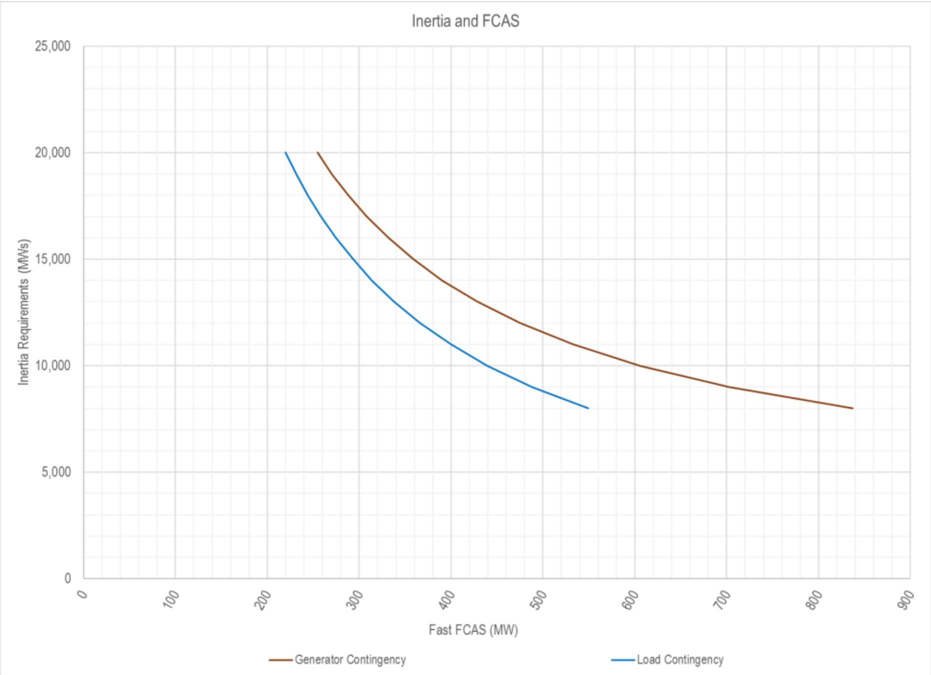
While Victoria is an *island* the following are the largest *credible contingency events* (currently there are no *protected events*):

- **Generation Contingency**: Loy Yang A *generating unit* 2 has the highest *inertia* and the equal highest Minimum Operating Level (300 MW). Loy Yang A *generating unit* 2 at its Minimum Operating Level was one Generation Contingency used.
- **Load Contingency**: The largest loss of *load* following a *contingency event* in Victoria is loss of one APD potline.

Step 2: Relationship between Fast FCAS and Inertia

Studies for Queensland demonstrated that a SMM can be used to establish a relationship between the level of *inertia* and the amount of Fast FCAS required to maintain an Acceptable Frequency in an *islanded region*.[49] Figure 11 shows this relationship for Victoria.

Figure 11 Relationship between Fast FCAS and inertia



Step 3: Inertia available through Fast FCAS

Victoria has a maximum of 1,031 MW of *fast raise services* that can be provided by *synchronous generating units* and *loads* (471 MW by *synchronous generating units* and 560 MW by *loads*). It also has a maximum of 763 MW of *fast lower services* that can be provided by *synchronous generating units*.[50] When a *synchronous generating unit* is *dispatched* to provide Fast FCAS it will invariably bring *inertia* to

[49] POE 99 demand of the previous year and 1.5% load relief have been used in the analysis.

[50] As detailed in AEMO's NEM Registration and Exemption List. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists. The list *published* as at 11 April 2018 was used to complete the analysis to *publish* the *inertia requirements* by 30 June 2018.

the *power system*. For example, *dispatching* 1,031 MW of *fast raise services* or 763 MW of *fast lower services* would add 28,000 MWs[51] of *inertia* to Victoria.

At 300 MW output, Loy Yang A and Loy Yang B cannot provide *fast lower services*. For the largest Load Contingency, trip of one APD potline, it is assumed that not all *fast lower services* need to be available and, therefore, the largest Generation Contingency is left at 300 MW. In this instance, the *fast lower services* and *inertia* of *generating units* that cannot provide *fast lower services* at 300 MW are excluded from the calculation of the relationship between Fast FCAS and *inertia* available by *dispatching* Fast FCAS. The relationship is derived by assuming a linear relationship from an adjusted maximum of 283 MW of *fast lower services* and the attendant 15,300 MWs of *inertia*, back to the origin.

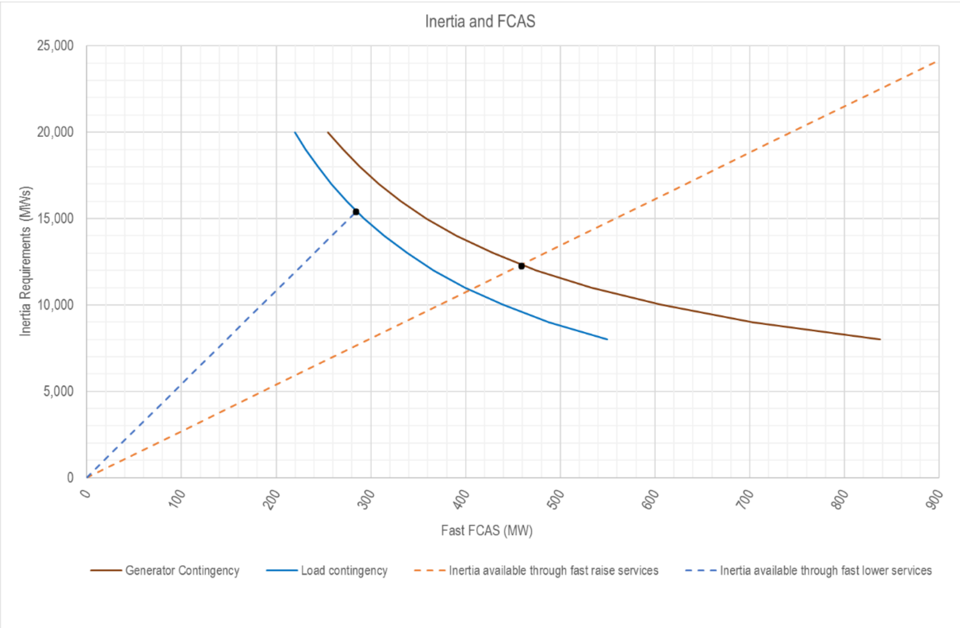
Figure 12 includes traces for both *fast lower services* relationships and one for the *fast raise services* relationship.

Step 4: Secure Operating Level of Inertia

Figure 12 illustrates the relationship between *inertia* and Fast FCAS required to maintain an Acceptable Frequency for the largest Generation Contingency and Load Contingency, as determined in step 1. The intersection of each curve with its relevant line indicates the *secure operating level of inertia* for the largest Generation Contingency or Load Contingency, as applicable.

Therefore, the *secure operating level of inertia* is 15,400 MWs[52]. This level of *inertia* would maintain an Acceptable Frequency for the largest Generation Contingency or Load Contingency.

Figure 12 Relationship between Fast FCAS and inertia



C.2 Minimum threshold level of inertia

The *generating unit* with the highest *inertia* in Victoria is Loy Yang A *generating unit* 2 with 2,752 MWs of *inertia*. Therefore:

Minimum threshold level of inertia = 15,400 MWs – 2,752 MWs = 12,648 MWs

The *minimum threshold level of inertia* for Victoria is 12,600 MWs.[53].

[51] Rounded to the nearest 100 MWs
[52] Rounded to the nearest 100 MWs.
[53] Rounded to the nearest 100 MWs.

APPENDIX D. INERTIA REQUIREMENTS FOR SOUTH AUSTRALIA

For the purpose of calculating the *inertia requirements* for SA, AEMO used a PSCAD model of the SA *power system*. This detailed model respresents the accurate FRT behaviour of wind farms, which is often important for calculating *inertia requirements* in a *region* where *asynchronous generation* is high compared to *synchronous generation*.

Appendix D shows AEMO's calculations of the *inertia requirements* for SA using the methodology outlined in Section 11.

D.1 Secure operating level of inertia

Step 1: Identification of relevant contingencies while islanded

While SA is an *island* the following are the largest contingencies:

- **Generation Contingency**: Lake Bonney Wind Farm is the largest *generating system* in SA, but it does not provide *inertia*. Moreover, *generation* from this *generating unit* can be reduced while still meeting *regional* demand from other *generating units.* Pelican Point has the largest *generating unit* with the highest *inertia*. Along with *inertia*, it also contributes to system strength. Considering the size of the loss of *generation* and *inertia*, Pelican Point Gas Turbine unit at its Minimum Operating Level was the Generation Contingency utilised[54].
- **Load Contingency:** The largest loss of *load* following a *contingency event* would be the Olympic Dam *load*.

SA has a total 1800 MW of *asynchronous generation*[55]. The majority of this is electrically close to each other. A *transmission* fault in SA would mean that the majority of its *generation* would go through its FRT mode, withdrawing the majority of the *generation* temporarily. This temporary loss of *generation* further impacts the *frequency* change.

Step 2: Relationship between Fast FCAS and inertia

Figure 13 shows the relationship between the *inertia* and amount of Fast FCAS required to maintain an Acceptable Frequency. Only the Generation Contingency is shown as this is more onerous than *load contingency*[56]. This relationship is achieved using PSCAD model for SA.

Step 3: Inertia available through Fast FCAS

SA has 212 MW of *fast raise services* and *fast lower services*[57]. Out of these, 63 MW is available by the Hornsdale Power Reserve. When a *synchronous generating unit* is *dispatched* to provide Fast FCAS it will invariably bring *inertia* to the *power system*. However, when Hornsdale Power Reserve is *dispatched* to provide Fast FCAS it will not add *inertia* to the *power system.* For SA, *dispatching* 212 MW of Fast FCAS would add 13,200 MWs[58] of *inertia* considering the combined *inertia* of all Fast FCAS providers in SA.

Step 4: Secure Operaing Level of Inerita

Figure 14 illustrates the relationship between *inertia* and Fast FCAS required to maintain an Acceptable Frequency for the largest Generation Contingency, as determined in step 1. It also shows a linearized

[54] Further details of this contingency and its impact on the SA *power system* is provided in a separate report. Available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review

[55] Generation information page. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. The list *published* as at 11 April 2018 was used to complete the analysis to *publish* the *inertia requirements* by 30 June 2018

[56] Further details are provided in a separate report. Available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review

[57] As detailed in AEMO's NEM Registration and Exemption List. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists. The list *published* as at 11 April 2018 was used to complete the analysis to *publish* the *inertia requirements* by 30 June 2018.

[58] Rounded to the nearest 100 MWs.

relationship between Fast FCAS and *inertia* available by *dispatching* Fast FCAS. The intersection of curves indicates the *secure operating level of inertia* for the largest Generation Contingency.

Therefore, the *secure operating level of inertia* is 6,000 MWs[59]. This level of *inertia* would maintain an Acceptable Frequency for the largest Generation Contingency or Load Contingency.

Figure 13 Relationship between Fast FCAS and inertia

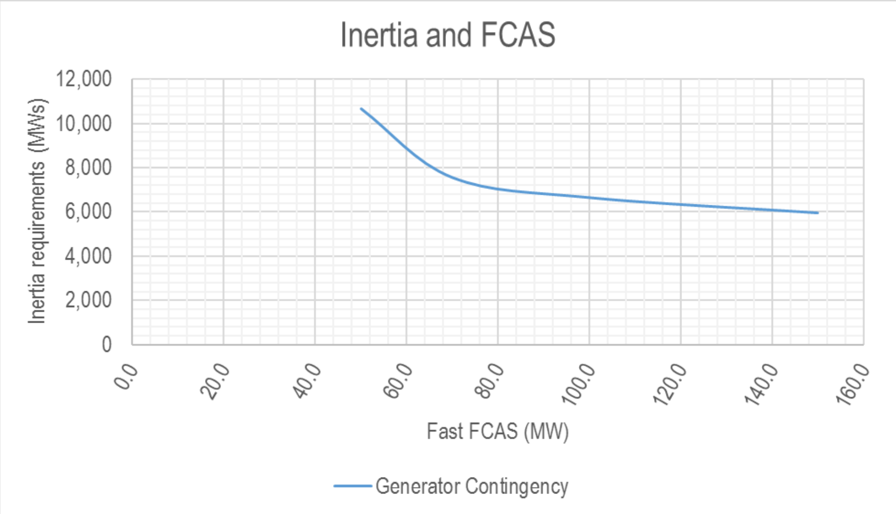
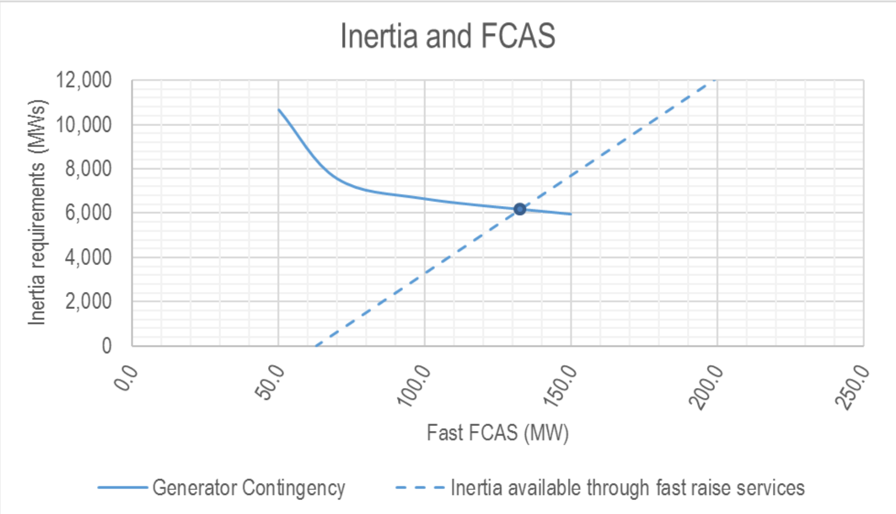


Figure 14 Relationship between Fast FCAS and inertia



D.2 Minimum threshold level of inertia

The *generating unit* with the highest *inertia* in SA is Pelican Point GT *generating unit* with 1,625 MWs of *inertia*. Therefore:

Minimum threshold level of inertia = 6,000 MWs – 1,625 MWs = 4,375 MWs

The *minimum threshold level of inertia* for SA is 4,400 MWs.[60]

[59] Rounded to the nearest 100 MWs.
[60] Rounded to the nearest 100 MWs.

APPENDIX E. INERTIA REQUIREMENTS FOR TASMANIA

At present, the vast majority of the *inertia* available in Tasmania resides within *transmission-connected synchronous generating units*. While it is recognised that there is a growing number of small *embedded generating systems* still using traditional *synchronous* machines, such as mini-hydro and small-frame gas turbines, the size of these *generating units* has typically been less than 5 to 7 MW. As a result, they provide a relatively minor contribution to *inertia*.

E.1 Operational differences between Tasmania and mainland regions

Tasmania is *connected* to the mainland via the Basslink HVDC *interconnector*. Basslink provides an *asynchronous connection* between the mainland and Tasmania. There are a number of operational measures in place for Tasmania that are different to any other *region* as a result of this arrangement.

E.1.1 Basslink interconnector

Loss of the Basslink *interconnector* is managed via the use of the Frequency Control System Protection Scheme (**FCSPS**). These schemes ensure that the *frequency operating standard* will be maintained if the *interconnector* trips and Tasmania forms an *island* by rapidly *disconnecting* armed *load* or *generation.*

For the purpose of calculating the *inertia requirements* for Tasmania, the loss of Basslink is actively managed through *central dispatch*.

E.1.2 Generating units

The majority of *generating units* in Tasmania are hydro with very low Minimum Operating Levels. This is different to the mainland, where Minimum Operating Levels are an important factor in determining *contingency events* that underlie *inertia requirements*.

At any given instant, to meet the supply-demand balance, sufficient *generating units* are required to be online at a sufficient operating levels to meet demand. This results in a wide possible range of *contingency events* that could be considered.

Therefore, Tasmania's hydro *generating units* will not be reduced to their Minimum Operating Levels for the purpose of calculating the *inertia requirements*.

E.1.3 Wind generation fault ride-through

Tasmania currently has around 308 MW of wind *generation*. During a fault, if the *voltage* at the terminal of these wind farms is below a specified threshold, these wind farms will enter FRT mode and temporarily reduce their *generation*. This temporary reduction in the wind *generation* increases the RoCoF of the *power system*. The transient energy deficit introduced by FRT characteristics can persist for up to 1 second, albeit that *active power* recovery commences as soon as *voltage* rises back above the FRT threshold level. The maximum rate of recovery is a function of the *network* strength at the wind farm *connection point*. On the occurrence of a *transmission* fault in Tasmania, it is reasonable to assume that all wind *generation* will enter into FRT mode. Therefore, the effect of this temporary reduction on RoCoF is considered when calculating *inertia requirements* for Tasmania.

E.1.4 RoCoF constraint

Since 2013, AEMO has used RoCoF *constraint* equations in Tasmania that maintain *frequency* transients within the *technical envelope* of the Tasmanian *power system* during periods of high power in-feed from *asynchronous generation* sources.

The maximum RoCoF must be limited to a value that does not result in the operation of anti-*islanding* protection (relevant to both *transmission-connected* and *embedded generation connected* to the *distribution network*) and ensures that all *synchronous generating units* remain transiently stable. A limit of ±3 Hz/s RoCoF with a filter and averaging period of approximately 100 ms after fault clearance is applied for any *credible contingency event*. Described as a general limit having a positive and negative slope, it is intended to apply to all types of *credible contingency events* affecting both *generation* and *load*.

In addition, TasNetworks has been applying a limit of -1.18 Hz/s when *frequency* passes through 49.0 Hz. A safety margin is applied that reduces the allowable RoCoF to 1.076 Hz/s for the purposes of *central dispatch*. This is to prevent operation of under-*frequency load shedding* relays that have been made sensitive to RoCoF.

The underlying principle is that an Acceptable Frequency should be maintained for *credible contingency events* expected to be managed by the *dispatch* of FCAS in combination with *inertia*, *inertia network services* or both.

Therefore, these RoCoF limits will be considered for the purpose of calculating the *inertia requirements*.

E.1.5 Load or generation shedding

Clause 5.20.7(a)(2) of the NER requires AEMO to consider "the maximum *load shedding* or *generation shedding* expected to occur on the occurrence of any *credible contingency event* affecting the *inertia sub-network* when the *inertia sub-network* is *islanded*".

Tasmania has SPSs that *disconnect generation* or *load* to reduce the imbalance between supply and demand following a *credible contingency event*. Key SPSs that influence the calculation of *inertia requirements* are outlined in Table 6.

Table 6 Tasmania power system – credible contingency event and special protection schemes

No	Description of contingency event	Maximum power imbalance	Relevant SPS	Residual power imbalance operation of relevant SPS
1	Loss of Basslink interconnector	630 MW export (to Victoria) 480 MW import (from Victoria)	Frequency Control Special Protection Scheme (FCSPS)	Power imbalance of ±40 MW for export Generation deficit between 74 MW and 161 MW for import
2	Loss of Tamar Valley Power Station	208 MW	TVPS Generator Contingency Scheme (GCS)	Between 127 MW and 144 MW

Therefore, the impact of these SPSs on the reduction of the size of *contingency events* will be considered for the purpose of calculating the *inertia requirements*,.

E.1.6 Adaptive under-frequency load shedding scheme 2 (AUFLS2)

The purpose of the scheme is to provide additional *fast raise services* in Tasmania by shedding *load* in response to a fall in *frequency*. AUFLS2 continuously calculates the RoCoF. When the trigger *frequency* is reached, it uses the calculated RoCoF to trip a variable number of *load* blocks. This scheme provides significant *fast raise services* but because it is *load* based, does so without the addition of any *inertia* to the power system. The amount of the service available through this scheme depends on the amount of available industrial *load*.

Therefore, the effect of AUFLS2 in reducing the *inertia requirements* will be considered for the purpose of calculating the *inertia requirements*.

E.1.7 Lower FCAS reduction scheme

The lower FCAS reduction scheme is designed to trip designated *generation* when the *power system frequency* rises above a *frequency* threshold between 51 Hz – 52 Hz[61]. This means a number of hydro *generating units* may trip, by design, for high *frequency* conditions in Tasmania following *single credible contingency events*, such as loss of *load* at Bell Bay Aluminium.

Therefore, the effect of lower FCAS reduction scheme in reducing the *inertia requirements* will be considered for the purpose of calculating the *inertia requirements.*

[61] The frequency operating band for a 'generation event' or a 'load event' is 48 to 52 Hz for Tasmania *island* operation. See Table A.2.2 of the *frequency operating standards*.

E.1.8 Water storage

Tasmania has a large number of hydro *generating units* whose operation relies not only on *market* conditions, but also on water storage levels. Often, the volume of water storage drives the amount of energy that Tasmania is likely to export to the mainland. This influences the *dispatch* of *generating units* in Tasmania and thereby the *inertia* available in the *region*.

Therefore, in determining the Typical Inertia in Tasmania, it would be prudent to look at more than one year's worth of historical data.

E.2 Inertia Requirements

Appendix E.2 shows AEMO's calculations of the *inertia requirements* for Tasmania using the methodology outlined in Section 11 and considering the operational differences between Tasmania and the mainland *regions* outlined in Section E.1.

E.2.1 Frequency operating standard

The following should be noted when applying the *frequency operating standard* in Tasmania:

- The *disconnection* of Tasmania from the mainland is treated as a 'network event', as this is always a credible contingency, and the 'interconnected system' provisions continue to apply[62].
- The 'islanded operation' provisions[63] only apply where an *island* has formed wholly within Tasmania, for example, an isolated west coast *network*.
- *Credible contingency events* must be managed within the range 48.0 to 52.0 Hz.[64]

E.2.2 Secure operating level of inertia

Step 1: Identification of Relevant Contingencies while Islanded

While Tasmania is an *island*[65] the following are the largest *credible contingency events* (currently there are no *protected events*):

- **Generation Contingency**: Considering the size of the largest loss of *generation* and *inertia*, Gordon unit Generation Contingency is utilised[66].
- **Load Contingency:** The largest loss of *load* following a *contingency event* in Tasmania would be the Rio Tinto potline.

Step 2: Relationship between Fast FCAS and Inertia

While Tasmania is an *island*, it is important to consider the effect of the FRT of wind farms on RoCoF and thereby *inertia requirements* to limit RoCoF. Figure 15 shows the FRT behaviour of those wind farms. The shaded area shows an energy deficit caused by the FRT characteristic of wind farms. This energy deficit will depend on the fault location, residual *voltage* and *voltage* recovery at the wind farm terminals.

The FRT characteristic shown in Figure 16 has been utilised for the purpose of calculating the *inertia requirements*.

[62] See Table A.2.1 of the *frequency operating standard*.
[63] Table A.2.2 of the *frequency operating standard.*
[64] Table A.2.2 of the *frequency operating standard.*
[65] Electrical island in the context of inertia requirements methodology.
[66] Consideration has been given to the exiting SPSs in the *region*.

Figure 15 Wind generation fault ride through in Tasmania

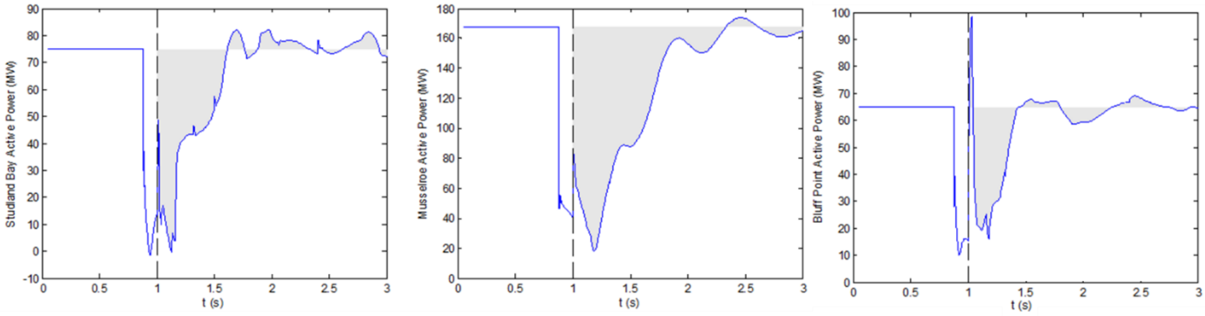


Figure 16 Wind farm FRT characteristic

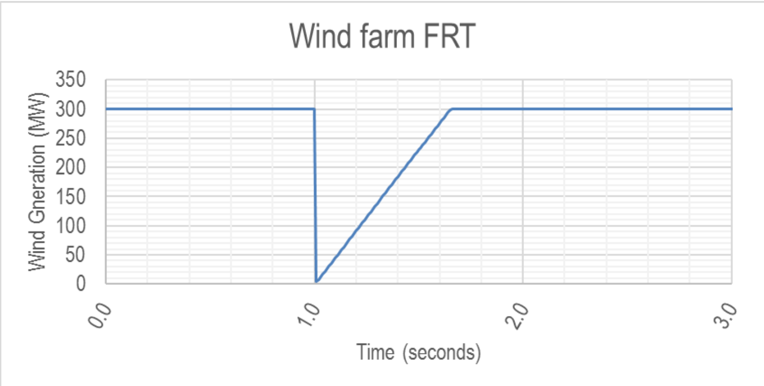
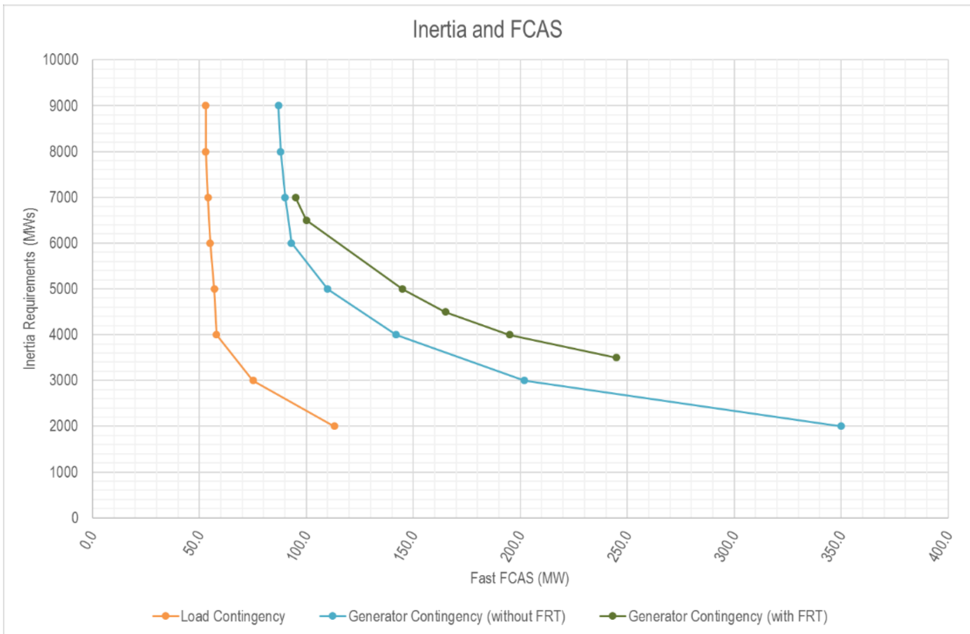


Figure 17 shows the relationship between the *inertia* required and Fast FCAS to maintain an Acceptable Frequency for the largest Generation Contingency and Load Contingency in Tasmania. The effect of FRT behaviour of wind farms is also shown in Figure 17.

Figure 17 Relationship between Fast FCAS and inertia



Step 3: Inertia available through Fast FCAS

Tasmania has 388 MW of *fast raise services* and 669 MW of *fast lower services* provided by *synchronous generating units*[67]. When a *synchronous generating unit* is *dispatched* to provide Fast FCAS it will invariably bring *inertia* to the *power system*. For example, *dispatching* 388 MW of *fast lower services* and 669 MW of *fast raise services* would add 8,900 MWs[68] and 11,200 MWs[69] of *inertia* respectively to Tasmania.

The *inertia* for different levels of Fast FCAS in Tasmania was calculated, and is displayed in Figure 18.

Step 4: Secure operating level of Inertia

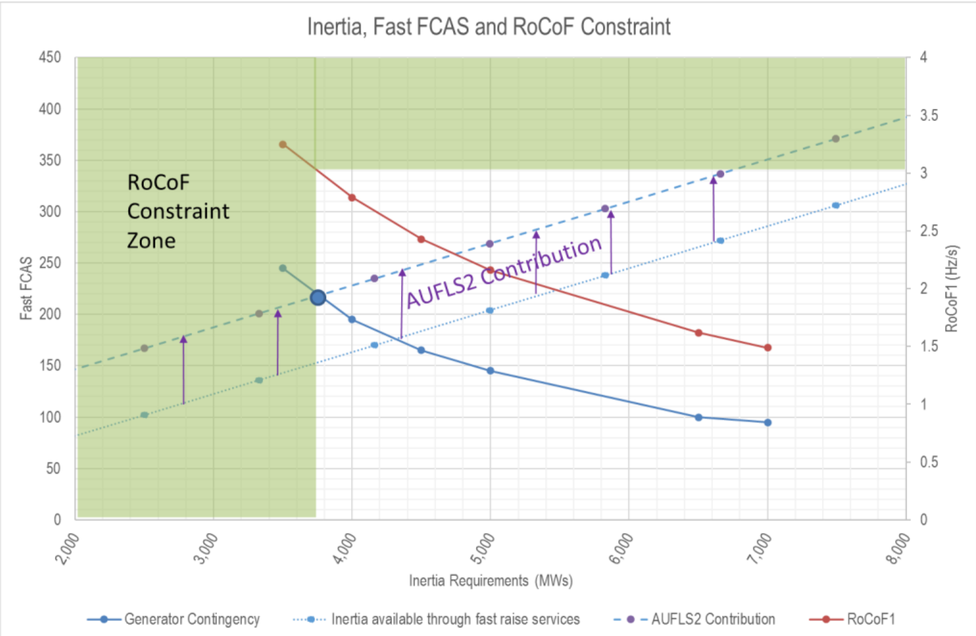
When calculating the *secure operating level of inertia* for Tasmania, the following is considered:

- RoCoF constraints: The maximum RoCoF must be limited to ±3 Hz/s with an averaging period of approximately 100 milliseconds after fault clearance. Moreover, it should be limited to 1.079 Hz/s when *frequency* passes through 49.0 Hz.
- AUFLS2: This scheme is designed to provide additional Fast FCAS by shedding *load* in response to a fall in *frequency.* The Fast FCAS contribution of 65 MW is considered.[70]

Figure 18 shows the relationship between *inertia* required and Fast FCAS to maintain an Acceptable Frequency for the largest Generation Contingency, as determined in step 1. It also shows the *inertia* available by *dispatching fast raise services* and effect of AUFLS2 in providing additional Fast FCAS. It shows the RoCoF limit that is currently being applied to the region. The intersection of the two curves indicates the *secure operating level of inertia*. This level of *inertia* also meets RoCoF constraints for Tasmania.

The *secure operating level of inertia* would be 3,800 MWs[71]. This level of *inertia* would maintain an Acceptable Frequency for the largest Generation Contingency or Load Contingency.[72]

Figure 18 Relationship between Fast FCAS and inertia



[67] As detailed in AEMO's NEM Registration and Exemption List. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists. The list *published* as at 11 April 2018 was used to complete the analysis to *publish* the *inertia requirements* by 30 June 2018.

[68] Rounded to the nearest 100 MWs.

[69] Rounded to the nearest 100 MWs.

[70] Average Fast FCAS provide by AUFLS2 between from the day it was commissioned and 1 June 2018.

[71] Rounded to the nearest 100 MWs.

[72] Load contingency has lower impact than generator contingency therefore it is not shown in Figure 18

E.3 Minimum threshold level of inertia

The largest *inertia generating unit* in Tasmania is Gordon with 625 MWs of *inertia*. Therefore:

Minimum threshold level of inertia = 3,800 MWs – 625 MWs = 3,175 MWs

The *minimum threshold level of inertia* for Tasmania is 3,200 MWs[73].

[73] Rounded to the nearest 100 MWs.

APPENDIX F. TYPICAL INERTIA FOR INERTIA SUB-NETWORKS

For the purpose of calculating the Typical Inertia, AEMO used *inertia* provided in mainland *inertia sub-networks* during the previous year, and for the Tasmanian *inertia sub-network* the previous three years.

Ideally, the *inertia* data used to calculate an *inertia sub-network's* Typical Inertia should come from periods that are relevant to the *inertia requirements,* such as when an *inertia sub-network* is *islanded* or at a credible risk of *islanding*. In practice, however, such data sets are either very small or non-existent for mainland *regions*[74] due to their rarity. Therefore, AEMO has used *inertia* data from the entire previous year to work out the Typical Inertia for each *inertia sub-network* other than Tasmania.

These Typical Inertia values will be conservative as the *inertia* in an *inertia sub-network* is likely to be higher when an *inertia sub-network* is at a credible risk of *islanding*. This is due to *synchronous generating units* being incentivised to come online by FCAS *constraints*, or the environmental conditions that increase the risk of *islanding* (e.g. bushfires) being correlated with high demand and, therefore, high *synchronous generating unit dispatch* and *inertia*. For example, Victoria has only *islanded* once since the *NEM* commenced in 1998, and this was during a high demand/*inertia* period instigated by bushfires.

Tasmania is always a *synchronous island* as it has no AC *connections* to other *regions*. Therefore, all historical *inertia* data is relevant to the calculation of Tasmania's Typical Inertia. The *generation dispatch*, and, hence, the *inertia* in Tasmania is influenced by the water storage level of its hydro-electric schemes. Therefore, the previous year's data does not reflect the typical level of *inertia* provided in Tasmania. Therefore, AEMO has calculated Typical Inertia values for each of the last three years and used the average of these for its *inertia shortfall* assessment.

Figure 19 to Figure 25 show the Typical Inertia available in each of the *inertia sub-networks*. Table 7 shows Typical Inertia available in each *region*.

Table 7 Typical inertia

Region	Typical Inertia level (MWs)
Queensland	26,800
New South Wales	32,600
Victoria	17,100
South Australia	6,200
Tasmania	6,000

[74] Tasmania is always a *synchronous island*. Basslink is a DC *connection,* therefore, it does not form a *synchronous connection* to Victoria.

Figure 19 Typical inertia - Queensland

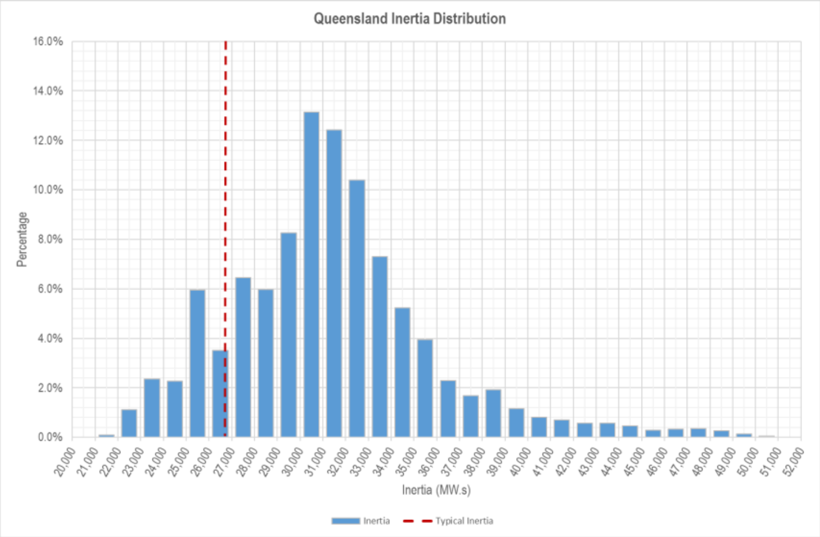


Figure 20 Typical inertia – New South Wales

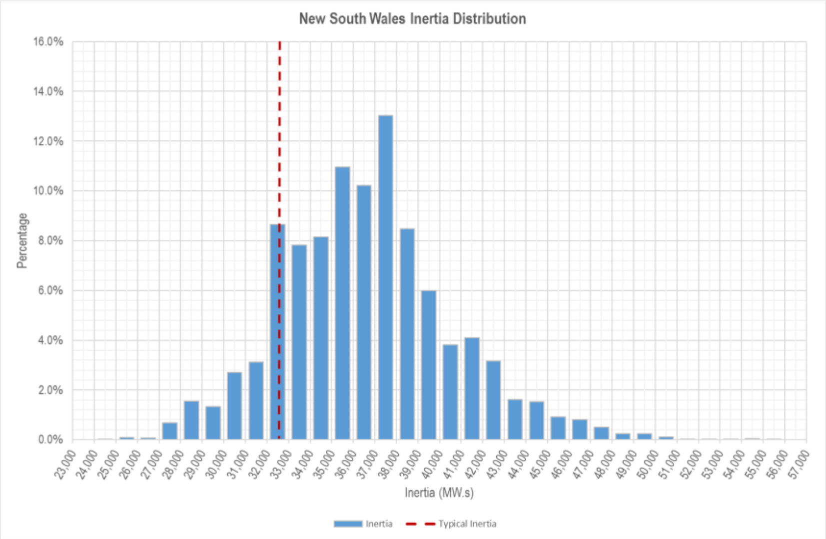


Figure 21 Typical inertia – Victoria

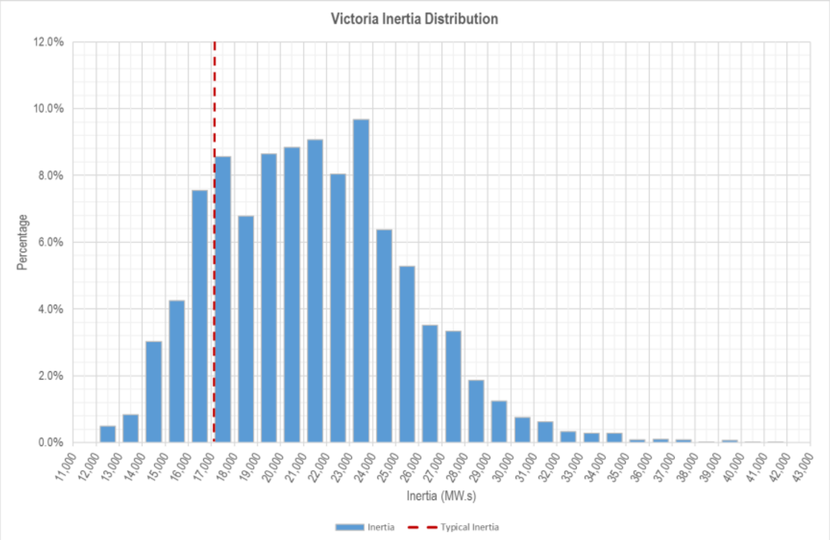


Figure 22 Typical inertia – South Australia

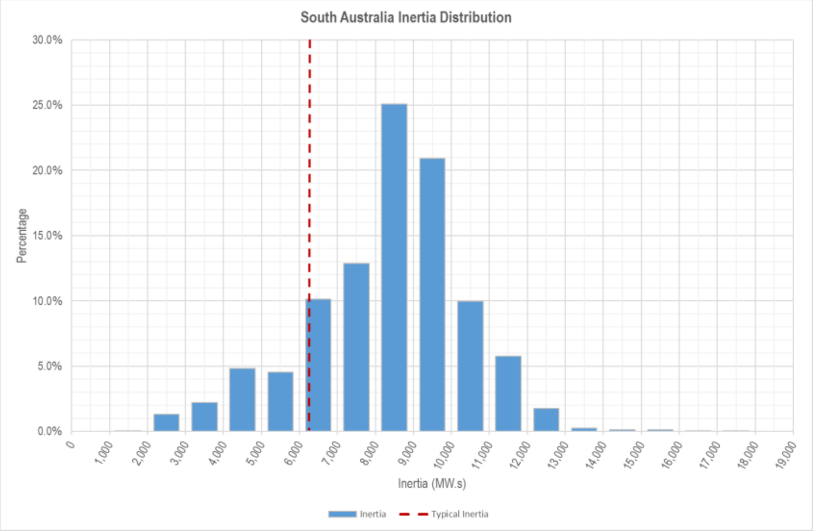


Figure 23 Typical inertia – Tasmania 2015

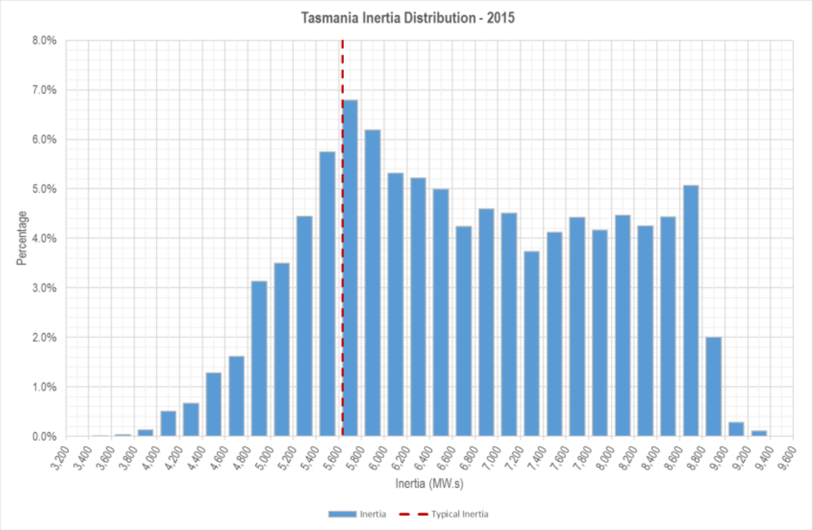


Figure 24 Typical inertia – Tasmania 2016

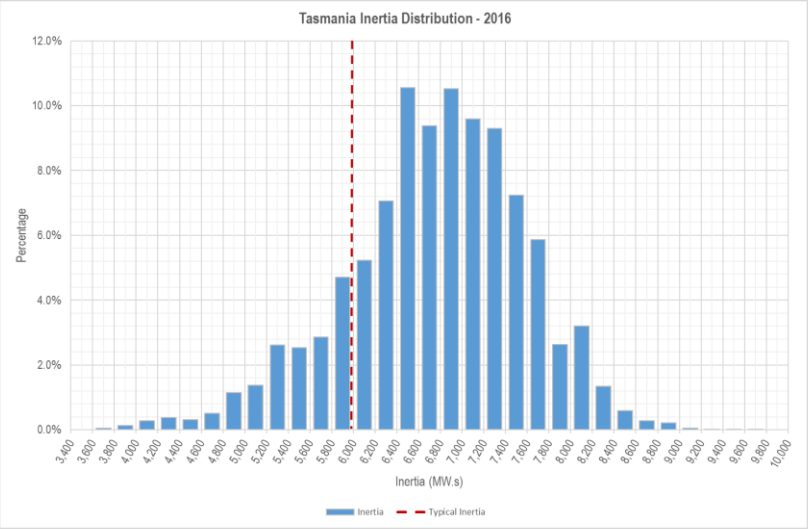
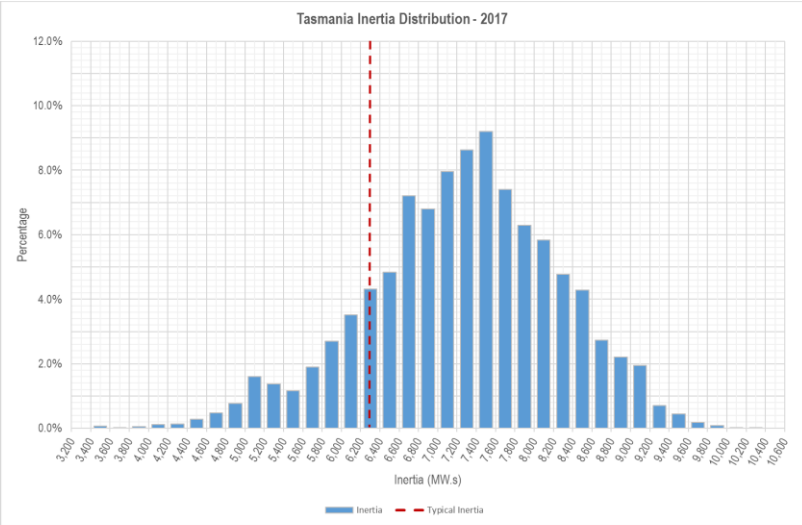


Figure 25 Typical inertia – Tasmania 2017



APPENDIX G. IMPACT OF FAST FREQUENCY RESPONSE

Appendix G examines the relationship between *inertia support activities* such as FFR and the *inertia requirements*.

G.1 Introduction

The specification of Fast FCAS in the *NEM* requires full delivery within six seconds. A key assumption in previous calculations of inertia requirements is that the full 6 second time period is required for complete delivery of a Fast FCAS response.

If however a FCAS response can be fully delivered in less than 6 seconds, this allow the Frequency Standards to be met with *dispatch* of less *inertia,* for a given contingency size. This suggests a relationship between the speed of delivery of an FCAS response, and the required level of system *inertia*.

However, conditions of low *inertia* also increase the RoCoF following a contingency. If *inertia* levels are reduced due to faster delivery of an FCAS response, this high RoCoF could itself be a limiting factor for operation of the *power system* in a *secure operating state*.

As described in Section 9.2, *inertia support activities* that rely on the measurement of *frequency* to increase/decrease their output need a minimum time to operate successfully, and this becomes increasingly challenging under high RoCoF conditions

G.2 Fast Frequency Response (FFR) model

During this analysis an FFR model with the following settings has been used:

- Negligible response delay or ramp rate restrictions once activated
- Frequency deadband of +/- 150 mHz
- 1.7% frequency droop.

Measurement time delay of 150ms[75] These settings result in full activation of the response by the time frequency reaches 49 or 51 Hz.

G.3 Analysis

To assess the impact of FFR on *inertia requirements*, this generic FFR model was integrated into a single mass frequency model, and the total Fast FCAS response was divided into two components:

- Fast FCAS delivered as per the requirements set out in MASS[76]; and
- FFR that represents the FFR model explained in previous Appendix G2.

To understand the relationship between the amount of FFR and the *inertia requirements*, the percentage contribution from FFR to the total required Fast FCAS response was varied. For each case, a revised *inertia requirement* was calculated to maintain Acceptable Frequency.

Figure 26 shows the relationship between FFR and *inertia* reduction that could be achieved to maintain an Acceptable Frequency. The horizontal axis shows the percentage FFR from the total Fast FCAS that was *dispatched*. As an example, 30% indicates 30% FFR and 70% Fast FCAS. The vertical axis shows the percentage of *inertia* reduction that can be achieved. As an example, 10% indicates that 10% less *inertia* is required to maintain Acceptable Frequency.

Figure 26 demonstrates that FFR is more effective for low *inertia* systems compared to high *inertia* systems. As an example, for a contingency size of 300 MW, *dispatching* 20% FFR from total Fast FCAS would provide 6.5% and 17% reduction in the *inertia requirements* for an *inertia sub-network* with 20,000 MWs and 15,000 MWs *inertia,* respectively.

Figure 27 shows the relationship between FFR and contingency size and demonstrates that FFR is more effective for larger contingencies.

[75] Some measurement units can accurately measure singal value quicker than 150ms.

Figure 28 shows the relationship between FFR and RoCoF. The horizontal axis shows the percentage of FFR from the total FCAS *dispatched*. Whilst a higher percentage of FFR can achieve a reduction in the *inertia requirements* as shown in Figure 26, it will also increase the RoCoF as shown in Figure 28.

Figure 28 highlights that for a contingency size of 300 MW, only 15% of fast FCAS can be *dispatched* as FFR for an *inertia sub-network* with 10,000 MWs *inertia* to limit RoCoF to 1 Hz/s. However, for the same contingency size, 50% of Fast FCAS can be *dispatched* as FFR for an *inertia sub-network* with 15,000 MWs *inertia* to limit RoCoF to 1 Hz/s.

This analysis shows that for reducing *inertia requirements*, FFR is more effective for low *inertia* system with large contingency size. However, a low *inertia* system with a large contingency size is exposed to high RoCoF, which could be a limiting factor in the accurate delivery of FFR.

Figure 26 Relationship between FFR and Inertia

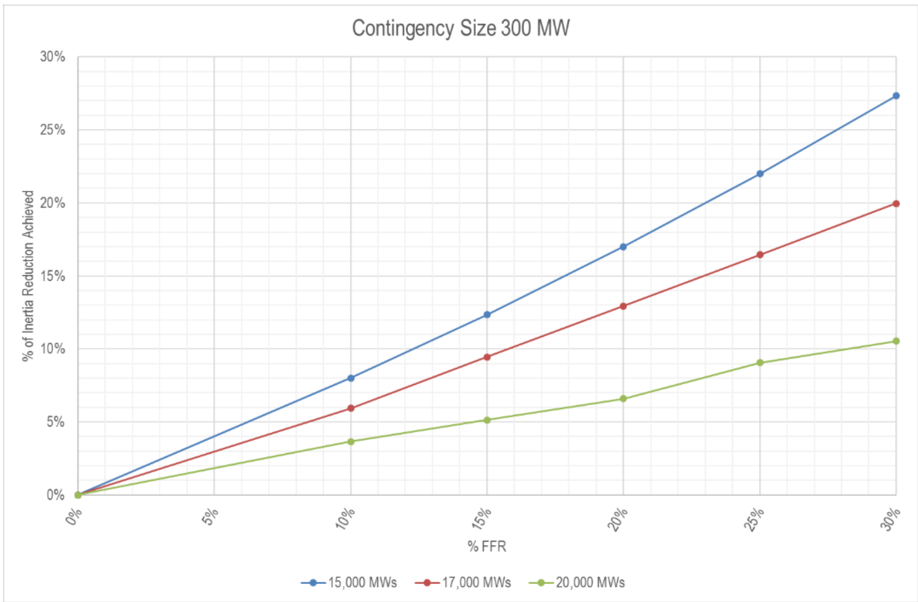


Figure 27 Relationship between FFR and Contingency

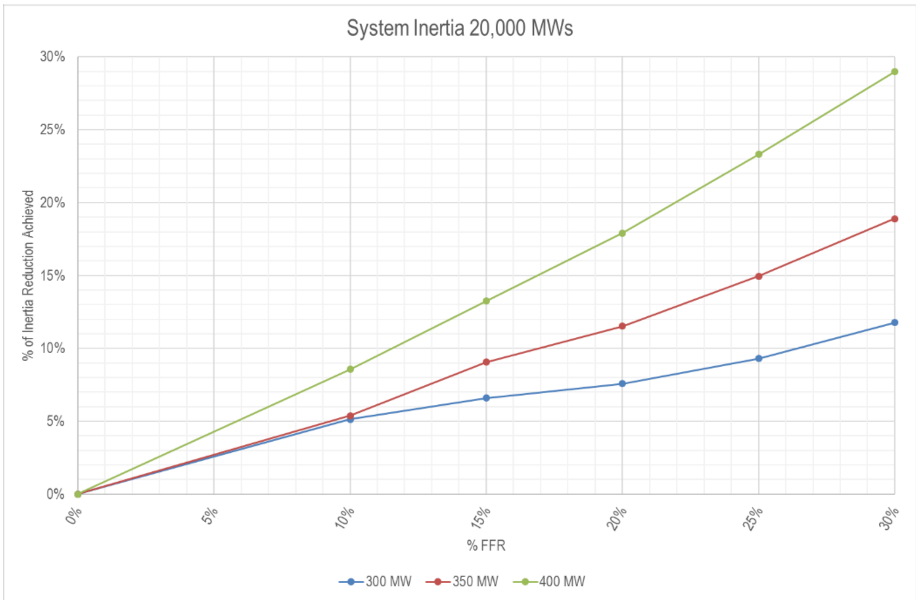
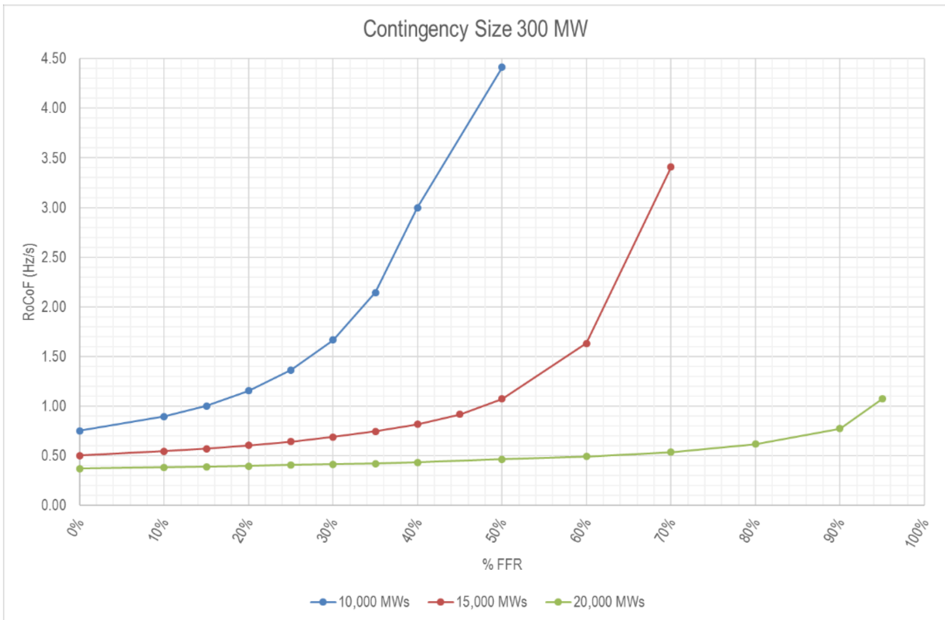


Figure 28 Relationship between FFR and RoCoF



G.4 Conclusions

This analysis indicates the potential for FFR-type technologies to reduce the *inertia requirements* for an *inertia sub-network*. For an *inertia sub-network* that typically has low *inertia* compared to the largest contingency size, FFR is more effective at reducing the *inertia requirements* than in an *inertia sub-network* with typically high levels of *inertia*. However, a low *inertia* system would be constrained by RoCoF, which would then limit the extent to which FFR could reduce the *inertia requirements,* i.e. a certain level of *inertia* provided by Synchronous Machines will still be required.

APPENDIX H. IDENTIFYING GENERATION CONTINGENCY

Appendix H provides an example on how to identify the Generation Contingency in an *islanded 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*.

The RoCoF resulting from a *contingency event* is a good indicator of the relationship between these two outcomes.

Table 8 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 MWs and 4100 MW, respectively.

Table 8 Generation and inertia outcomes

Contingency event No	Contingent inertia (MWs)	Loss of generation (MW)	RoCoF (Hz/s)
1	2500	150	0.30
2	3200	150	0.32
3	500	175	0.30
4	3200	100	0.21

Table 8 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.