2024 Inertia Report

December 2024

A report for the National Electricity Market

We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

The purpose of this publication is to report on the boundaries of the inertia sub-networks, the inertia requirements for each inertia sub-network for the coming 10-year period for the National Electricity Market, the the assumptions, considerations and matters that AEMO has taken into account to determine the inertia requirements and the binding interia requirements. AEMO publishes this 2024 Inertia Report in accordance with clause 5.20.5 of the National Electricity Rules. This publication is generally based on information available to AEMO as at November 2024 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	2/12/2024	Initial release.

Executive summary

This report updates AEMO's 10-year specification of inertia requirements for the National Electricity Market (NEM). Shortfalls are expected to emerge against these requirements in Queensland, and Tasmania over the next three years, unless adequate investment or services are provided by the relevant transmission network service provider (TNSP) in each region.

In undertaking this 2024 assessment, AEMO calculated the minimum inertia requirements that apply in each region over a 10-year horizon, and the likelihood of each region becoming islanded from the remainder of the NEM. These values aim to ensure that all regions have adequate frequency control services in place to operate securely and independently when needed.

For the first time in 2024, the *Inertia Report* also considers the *system-wide inertia level* requirement, and *inertia sub-network allocations* of this requirement that applies to the mainland when planning for fully interconnected operation, and to promote distributed inertia procurement across the NEM.

This report builds on regulatory changes introduced in March 2024 through the Australian Energy Market Commission's (AEMC's) Improving security frameworks for the energy transition rule[1], and AEMO's subsequent consultation on the Inertia Requirements Methodology[2]. All calculations consider the impact of frequency control services available through the 1-second frequency control ancillary services (FCAS) market.

AEMO has calculated inertia requirements for all NEM regions, for the next ten years

Table 1 summarises the inertia requirements for each NEM region that apply when planning for islanded operation, or credible risk of islanding (secure level) and for interconnected operation (the *inertia sub-network allocations* of the *system-wide inertia level*). These requirements form the basis of investment obligations that TNSPs must deliver from 1 December 2027.

Table 1 Summary of inertia requirements from 2 December 2024 to 1 December 2034

Region	Assumed level of 1-second FCAS (MW)	*Satisfactory inertia level* (MWs)	*Secure inertia level* (MWs)	*Inertia sub-network allocation* (MWs)[A]	Likelihood of islanding
New South Wales	-	10,000	12,500	9,600	Unlikely
Queensland	165	12,000	13,700	10,500	Likely[B]
South Australia	315	4,100	5,600	4,300	Likely[C]
Tasmania	-	3,200	3,800	-	Likely
Victoria	400	13,700	15,400	11,800	Unlikely

MW: megawatts, MWs: megawatt seconds

A. The *inertia sub-network allocation* is the regional allocation of the new *system-wide inertia level* that Inertia Service Providers need to plan for from 1 December 2027.

B. AEMO considers Queensland is likely to island until QNI connect is commissioned and a control scheme exists to manage the non-credible loss of QNI and QNI connect.

C. AEMO does not consider South Australia to be sufficiently likely to island following the expected commissioning of Project Energy Connect (PEC) Stage 2 and once necessary protection schemes are in place to manage the non-credible loss of PEC itself or the Heywood interconnector.

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[1] At https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

[2] At https://www.aemo.com.au/consultations/current-and-closed-consultations/amendments-to-the-inertia-requirements-methodology.

Without investment, near-term shortfalls are expected across two regions

AEMO modelled the projected availability of inertia over a three-year period from December 2024 to December 2027. These projections were used to identify shortfalls as part of the 2024 Network Support and Control Ancillary Services (NSCAS) Report[3], and a summary of these findings is presented in Table 2.

Table 2 Summary of projected inertia shortfalls

Region	Projected inertia shortfalls
 **New South Wales**	**No inertia shortfalls have been identified,** and Transgrid must ensure sufficient inertia is available to meet their full *inertia sub-network allocation* from 1 December 2027.
 **Queensland**	**The previously declared inertia shortfall in Queensland for islanded conditions decreased in magnitude to 256 MWs in 2027-28.** Remediation may be possible in parallel with the existing Powerlink System Strength RIT-T.
 **South Australia**	**No inertia shortfalls have been identified,** and the existing inertia shortfall has been addressed, primarily through additional registrations in the 1-second Frequency Control Ancillary Services (FCAS) market.
 **Tasmania**	**Existing inertia shortfalls have been confirmed for the region.** Sufficient network support agreements are in place until 1 December 2025, and longer-term remediation may be possible alongside system strength remediation.
 **Victoria**	**The projected level of inertia is expected to fall below the *inertia sub-network allocation* for Victoria, however sufficient inertia is available to be shared from neighbouring regions.** AVP must ensure sufficient inertia is available to meet their full *inertia sub-network allocation* from 1 December 2027.

AEMO is seeking feedback on key inputs for the 2025 inertia assessment

AEMO takes a consultative approach to reviewing *inertia requirements* each year and intends to use feedback on each annual report to inform future reports. Stakeholders are encouraged to provide feedback to planning@aemo.com.au on the presentation of results, and the matters considered in this report.

To allow adequate consideration ahead of scoping and development for the 2025 report, AEMO seeks feedback by 28 February 2025.

[3] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.

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1 Introduction

In the context of the power system, inertia describes an immediate and inherent electrical response from connected devices that acts to oppose changes in frequency. Ensuring sufficient levels of inertia are available allows the power system to resist large changes in frequency that can arise following a contingency event.

Each year, AEMO assesses and publishes the regional requirements for inertia to allow subsequent delivery and maintenance by the transmission network service providers (TNSPs) in each region. AEMO can also take action through its last resort planning functions in the network support and control ancillary services (NSCAS) framework to ensure that the minimum levels published in this report can be met in the near term.

1.1 Regulatory changes impacting the 2024 Inertia Report

Inertia services can now be considered under the NSCAS framework

The Australian Energy Market Commission (AEMC) published the National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 (ISF Rule) in March 2024[4]. This rule expands the system security frameworks and provides AEMO with tools to manage security in the NEM through the energy transition.

With effect from 1 December 2024, the ISF Rule permits inertia network services to be considered under the NSCAS framework (removing the previous exclusion of those services). While TNSPs have the primary obligation to procure services that meet the *inertia requirements*, AEMO is now also able to procure these services to fill near-term expected shortfalls via its NSCAS last resort functions.

As a result of this change, the inertia shortfalls that would previously have been discussed in this report are now declared in the 2024 *NSCAS Report*[5]. For completeness, this report still highlights those outcomes – however, this report now has a stronger focus on the calculation and presentation of the requirements themselves.

A new *system-wide inertia level* has been introduced with additional obligations on TNSPs

With respect to the *inertia requirements* published in this report, the ISF Rule also requires that AEMO develop a new *system-wide inertia level* for the mainland NEM regions which should apply when planning for fully interconnected system operation. Previously, *inertia requirements* were only applied when planning for islanded operation, or credible risk of islanding of individual regions or sub-regions.

TNSPs must ensure these services are available continuously, and within three years of the requirements being published. This is in addition to the existing islanded requirements, which AEMO will continue to update annually. TNSPs can procure synthetic inertia to meet their obligations, where such services have been approved by AEMO. Throughout 2024, AEMO has consulted on the new system-wide requirement calculation approach, and on a proposed inertia network services specification, as part of the *Inertia Requirements Methodology*[6].

[4] At https://www.aemc.gov.au/sites/default/files/2024-03/ERC0290%20-%20ISF%20final%20determination.pdf.

[5] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.

[6] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.

1.2 Scope of analysis

This report provides AEMO's 2024 assessment of *inertia requirements* over the 10-year period from December 2024 to December 2034 inclusive. The underlying analysis has been conducted in accordance with the latest *Inertia Requirements Methodology*, and includes requirements for the:

- ***Satisfactory inertia level***, 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.
- ***Secure inertia level***, 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.
- ***System-wide inertia level***, being the mainland inertia required to operate the mainland regions of the NEM securely.
- ***Inertia sub-network allocation***, being the portion of the *system-wide inertia level* allocated to that inertia sub-network.

In determining these requirements, AEMO considers the largest relevant credible contingency event, any consequential demand-side response, the levels of frequency control ancillary services (FCAS) available, and AEMO's operational procedures for periods where regions are islanded or at risk of islanding. Further details are available in Appendix A1.2.

AEMO has applied these requirements when assessing potential inertia shortfalls in the 2024 *NSCAS Report*. In undertaking that assessment, AEMO conducted extensive market modelling studies and estimated the expected levels of inertia available for at least 99.87% of the time in a typical year. While those outcomes (and any resulting gaps) are described in the *NSCAS Report*, key outcomes and additional modelling information are still included on a regional basis in this report.

1.3 Structure of this report

The 2024 *Inertia Report* contains the following information:

- Determination of the *system-wide inertia level* (Section 2).
- For each region or combined region, AEMO's assessment of *inertia requirements* and islanding risk:
  - New South Wales (Section 3.1).
  - Queensland (Section 3.2).
  - South Australia (Section 3.3).
  - Tasmania (Section 3.4).
  - Victoria (Section 3.5).
- An overview of next steps related to the findings in this report (Section 4).
- An overview of the methodology and inputs used to prepare this report (Appendix A1).

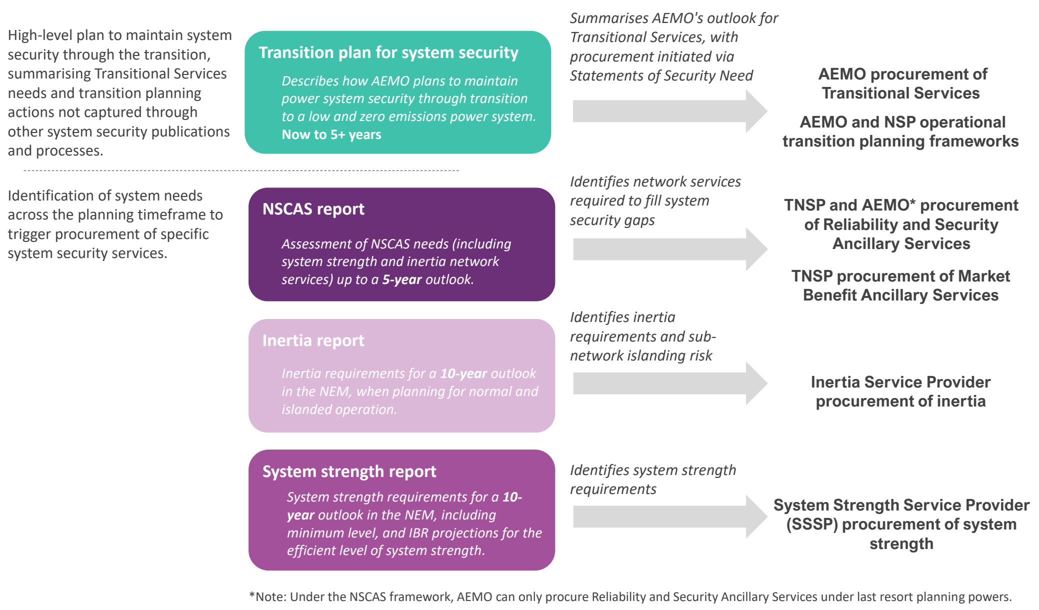
1.4 Relationship with other AEMO documents

Effective system security management requires a range of tools and frameworks working in tandem, across multiple timescales, participant types, and geographic areas. Figure 1 summarises AEMO's multilayered approach with respect to this report; and its relationship to other AEMO documents.

While procurement of security services is typically the role of the TNSP, AEMO has specific roles to:

- **Set minimum security requirements** for inertia and system strength over a 10-year horizon; which must then be planned for and delivered by the relevant network business in each region. This is done through the respective annual *Inertia Report* and *System Strength Report*.
- **Act as a last resort planner** where security needs emerge faster than normal TNSP planning processes can accommodate. This is done annually with a three- to five-year outlook horizon through the *NSCAS Report*, and AEMO is able to procure last-resort services through this framework.
- **Map and respond to future engineering challenges and transition points** associated with operating a 100% renewable power system. This is done through AEMO's Engineering Roadmap, which prioritises the critical engineering actions; and through AEMO's new *Transition Plan for System Security* which provides an outlook of transition planning activities and transitional services needed to support a low-emissions power system.
- Coupling with these security focused functions, AEMO also publishes the *Integrated System Plan* (ISP)[7] and the Electricity *Statement of Opportunities* (ESOO)[8], which present a long-term view of the power system under a range of possible future scenarios.

Figure 1 Relationship between AEMO system security reports and *Transition Plan for System Security*



[7] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

[8] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

2 System-wide inertia level

- **For the first time, this 2024 report considers the *system-wide inertia level* requirements that apply on the mainland when planning for fully interconnected operation**, and how these should be distributed to ensure balanced delivery of inertia across all regions.
- **AEMO determined the system-wide minimum requirement to be 36,200 megawatt seconds (MWs)**, representing an efficiency of approximately 70% compared to the sum of individual islanded region requirements (51,000 MWs). This shows that significant inertia sharing is possible between regions, however inertia sharing does have limits, and this value remains well above the maximum islanded regional requirement (15,400 MWs in Victoria).

Inertia is not a purely global quantity across the NEM. The effectiveness of inertia in one region to provide frequency support in another region is highly sensitive to network topology, the nature of supply and demand along the corridor between the regions, intervening network limitations, and a range of other system conditions in effect during frequency disturbance events.

To determine the *system-wide inertia level* requirements, iterative power system simulation studies were performed on the interconnected power system, as described in the *Inertia Requirements Methodology*[9]. The most significant credible contingencies were applied in each region while varying the levels of available inertia to find the marginal level required to withstand all credible events. The success criteria used are outlined in Appendix A1, and Figure 2 provides a graphical view of the methodology, including key inputs and modelling tools used.

This is an iterative process that converges towards a set of overall minimum requirements for the system. The proportion of system-wide inertia carried by each region was also assessed with regard to the islanded regional requirements to minimise any large swings in local *inertia requirements* following separation events.

Table 3 provides a summary of the *inertia sub-network allocation* of the system wide inertia requirement. This forms the basis for TNSP obligations to procure sufficient inertia assets or services to guarantee these levels will be available continuously in their respective regions from 1 December 2027. This obligation is in addition to the existing secure regional (islanded) *inertia requirements*, presented for each region in Section 3.

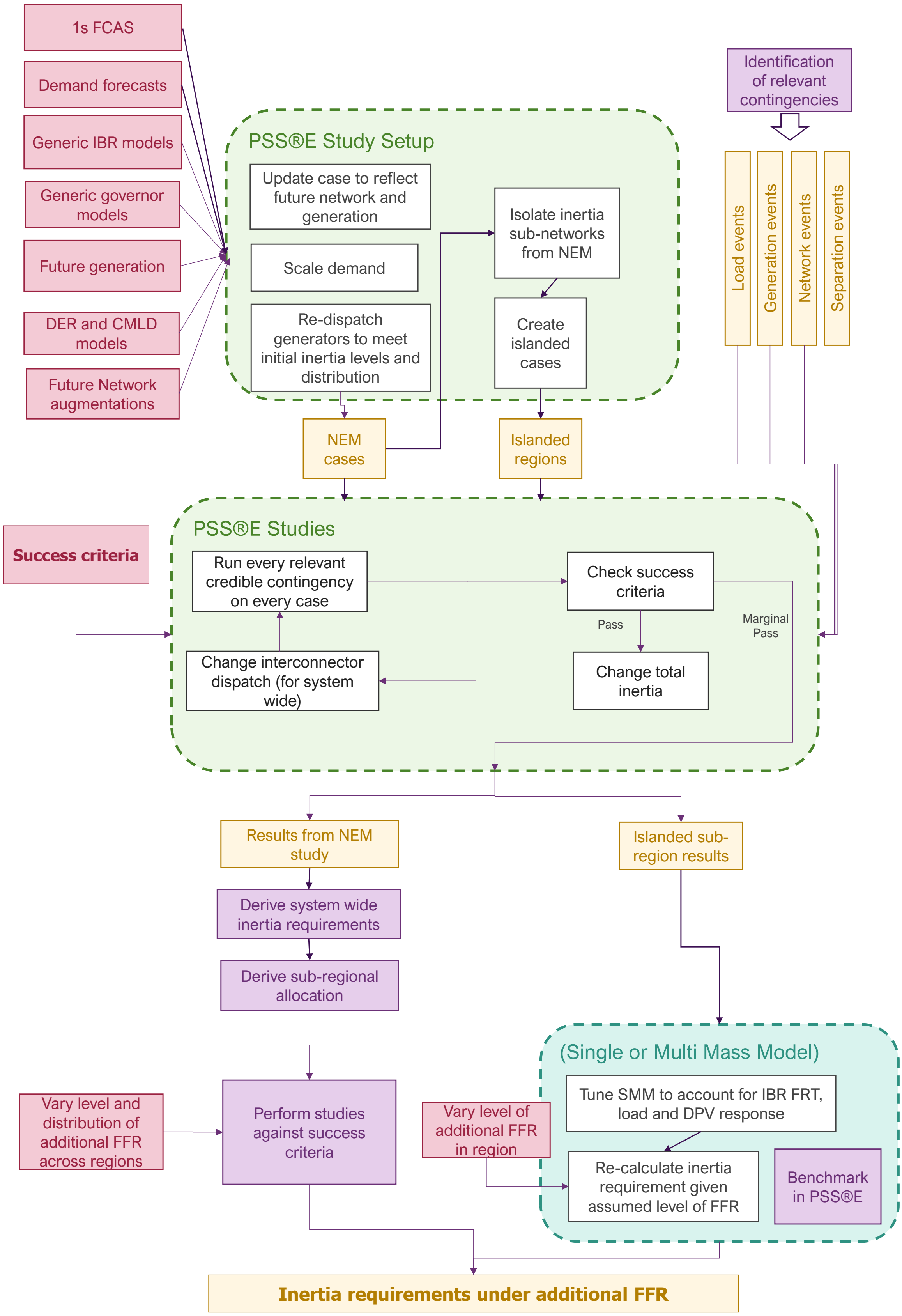
Table 3 Inertia sub-network allocation

Region	*Inertia sub-network allocation* %	*Inertia sub-network allocation* (MWs)
New South Wales	26.52%	9,600
Queensland	29.01%	10,500
South Australia	11.88%	4,300
Victoria	32.60%	11,800

Note: The system-wide level of inertia requirement only applies to mainland NEM regions, so Tasmania is not included in this table.

[9] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.

Figure 2 Overview of approach to determining inertia requirements



3 Regional inertia requirements

3.1 New South Wales

- AEMO undertook a preliminary review of the *satisfactory* and *secure inertia levels* for New South Wales based on the latest power system modelling inputs, including distributed photovoltaic (PV) response characteristics for the region, and determined that the previous requirements remain appropriate. AEMO has also assessed New South Wales as unlikely to island from the remainder of the NEM, given its strong interconnection with neighbouring regions.
- No inertia shortfalls have been identified over the three-year assessment horizon, however Transgrid is required to ensure sufficient supplies are available to meet its *inertia sub-network allocation* from 1 December 2027.

Table 4 provides a summary of the *inertia requirements* for New South Wales, including the satisfactory and secure levels of inertia when planning for islanded operation, and the regional allocation of the system-wide level.

Table 4 New South Wales *inertia requirements* from 2 December 2024 to 1 December 2034

Quantity	Value
Satisfactory inertia level	10,000 MWs
Secure inertia level	12,500 MWs
Inertia sub-network allocation	9,600 MWs
Likelihood of islanding	Unlikely

Potential inertia shortfalls

Inertia shortfalls are now formally assessed and declared through the annual *NSCAS Report*[10] over a three-year outlook period. The latest modelling for that report indicates that projected levels of inertia are expected remain above the New South Wales *inertia sub-network allocation*. Transgrid must ensure sufficient inertia is available to meet their full *inertia sub-network allocation* from 1 December 2027.

As part of that assessment, AEMO deemed New South Wales unlikely to island on its own[11] given its strong interconnection with neighbouring regions, so does not expect any shortalls against the the *satisfactory* or *secure inertia levels*.

[10] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.

[11] Historically AEMO has assessed a scenario where the NEM has separated with Queensland and New South Wales forming an island. For completeness, AEMO has confirmed that no inertia shortfall exists for this scenario with updated inputs in 2024, however AEMO considers that the *system-wide inertia level* requirement assessment should supersede the need for this scenario in future.

Likelihood of islanding

Table 5 presents the criteria assessed when determining the likelihood of the New South Wales inertia sub-network islanding from the remainder of the system.

Table 5 Assessment of the likelihood of New South Wales islanding

Criterion	New South Wales
Inertia levels typically provided	18,254 MWs
Inertia levels compared to *secure inertia* level	Inertia levels forecast to be above the *secure inertia level* until after 2027-28.
Inertia sub-network allocation	9,600 MWs
Existing interconnections	One 220 kilovolts (kV), three 330 kV alternating current (AC), and two 132 kV AC connections to Victoria. One 330 kV AC double-circuit and one direct current (DC) link connection to Queensland.
Future interconnections and status	Project EnergyConnect (PEC): 330 kV double-circuit to South Australia and 220 kV double-circuit to Victoria (Stage 1: 2024, Stage 2: 2027). Victoria – New South Wales Interconnector West (VNI West): 500 kV double-circuit to Victoria (2029). Queensland – New South Wales Interconnector (QNI) Connect: 330 kV double-circuit to Queensland (2033).
History of islanding	N/A
Applicable control schemes	N/A
Likelihood of islanding after contingency event	Not likely

Cooptimisation with contracted fast frequency response (FFR) and 1-Second FCAS

AEMO undertook preliminary reviews of the 2018 New South Wales *secure* and *satisfactory inertia level* requirements, and confirmed that these previous requirements remain appropriate. AEMO will continue to monitor *inertia requirements* in New South Wales. As such, diagrams representing the relationship between contracted FFR and 1-second FCAS have not been generated at this time for New South Wales. Due to strong interconnection between New South Wales and neighbouring regions, the *secure inertia level* requirement is unlikely to bind.

3.2 Queensland

- AEMO updated the *satisfactory* and *secure inertia levels* for Queensland based on the latest power system modelling inputs. AEMO also assessed Queensland as sufficiently likely to island from the remainder of the power system.
- No inertia shortfalls have been identified in Queensland against the *inertia sub-network allocation*, however the previously declared inertia shortfall in Queensland against the secure level of inertia has decreased in magnitude to 256 MWs in 2027-28.

Table 6 provides a summary of the *inertia requirements* for Queensland, including the assumed levels of 1-second FCAS available, the satisfactory and secure levels of inertia when planning for islanded operation, and the regional allocation of the system-wide level. Powerlink is required to ensure sufficient supplies are available to meet its *inertia sub-network allocation* from 1 December 2027.

Table 6 Queensland *inertia requirements* from 2 December 2024 to 1 December 2034

Quantity	Value
Assumed level of 1-second FCAS	165 MW
Satisfactory inertia level	12,000 MWs
Secure inertia level	13,700 MWs
Inertia sub-network allocation	10,500 MWs
Likelihood of islanding	Likely[A]

A. Queensland is likely to island until QNI Connect is commissioned and a control scheme exists to manage the non-credible loss of QNI and QNI Connect.

Potential inertia shortfalls

Inertia shortfalls are now formally assessed and declared through the annual *NSCAS Report*[12] over a three-year outlook period. The latest modelling for that report indicates that projected levels of inertia are expected to remain above the Queensland portion of the system-wide inertia requirement.

As part of this assessment, AEMO deemed Queensland sufficiently likely to island on its own, so assessed the region against its individual (islanded) *secure inertia level*. The previously declared inertia shortfall in Queensland against the *secure inertia level* has decreased in magnitude to 256 MWs in 2027-28. Powerlink is progressing inertia remediation activities in parallel with its System Strength Regulatory Investment Test for Transmission (RIT-T), and AEMO will continue to work with Powerlink to track the progress of these measures.

Likelihood of islanding

Table 7 presents the criteria assessed when determining the likelihood of the Queensland inertia sub-network islanding from the remainder of the system.

[12] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.

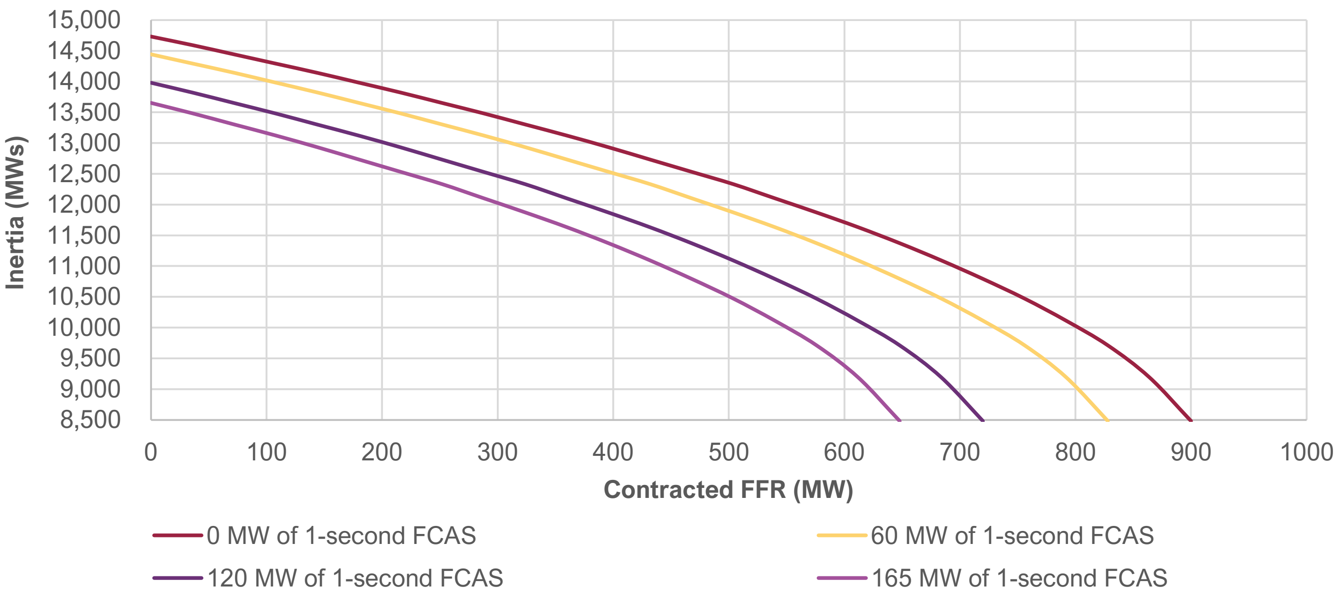
Table 7 Assessment of the likelihood of Queensland islanding

Criterion	Queensland
Inertia levels typically provided	16,579 MWs
Inertia levels compared to *secure inertia level*	*Inertia* levels forecast to be above the *secure inertia level* until 2027-28.
Inertia sub-network allocation	10,500 MWs
Existing interconnections	One 330 kV AC double-circuit and one DC link *connection* to New South Wales.
Future interconnections and status	QNI Connect: 330 kV double-circuit to Queensland (2033).
History of islanding	October 2021 August 2018
Applicable control schemes	N/A
Likelihood of islanding after contingency event	Likely

Cooptimisation with contracted FFR and 1-Second FCAS

In addition to the *inertia requirements* presented above, Figure 3 defines a set of operating points that would each ensure the system remains in a satisfactory frequency operating state, following a credible contingency event.

Figure 3 Relationship between inertia and fast frequency response in Queensland



The curves are intended to provide flexibility in the solutions used to address a declared shortfall. For example, an operating point below the curve would indicate a shortfall. This could be remediated by procuring inertia (moving up), contracting FFR services (moving right), or by procuring both services (moving both up and right). The optimal mixture will depend on the size and timing of the shortfall, and the options available in the region.

When determining *inertia requirements* in Queensland, AEMO used an operating point with no contracted FFR, and assumed 165 megawatts (MW) of 1-second FCAS, which is the amount of 1-second raise FCAS currently registered in Queensland. This is equivalent to 252 MW of contracted FFR[13]. Using this operating point reflects that during islanded operation, local FCAS prices are likely to incentivise capacity to become available.

Assuming a lower (or derated) value would increase obligations on the TNSP and require them to either contract with an equivalent amount of FFR outside the market, or procure other inertia services that reduce the demand for 1-second FCAS. In both cases, the amount of derating assumed becomes self-fulfilling by reducing either the demand or available providers in the 1-second market.

AEMO expects that a TNSP should consider the latest amount of registered 1-second FCAS when procuring FFR or inertia services. AEMO will continue to review *inertia requirements* annually.

[13] See Section A1.4.1 for details on this translation.

3.3 South Australia

- AEMO updated the *satisfactory* and *secure inertia levels* for South Australia based on the latest power system modelling inputs. AEMO also assessed South Australia as sufficiently likely to island from the remainder of the NEM until Project EnergyConnect (PEC) Stage 2 is commissioned, and necessary protection schemes are in place.
- No inertia shortfalls have been identified against these requirements over the three-year assessment horizon, however ElectraNet is required to ensure sufficient supplies are available to meet its *inertia sub-network allocation* from 1 December 2027.

Table 8 provides a summary of the *inertia requirements* for South Australia, including the assumed levels of 1-second FCAS available, the satisfactory and secure levels of inertia when planning for islanded operation, and the regional allocation of the system-wide level.

Table 8 South Australia *inertia requirements* from 2 December 2024 to 1 December 2034

Quantity	Value
Assumed level of 1-second FCAS	315 MW
Satisfactory inertia level	4,100 MWs
Secure inertia level	5,600 MWs
Inertia sub-network allocation	4,300 MWs
Likelihood of islanding	Likely[A]

A. AEMO does not consider South Australia to be sufficiently likely to island following the expected commissioning of PEC Stage 2 and necessary protection schemes are in place to manage the non-credible loss of either PEC itself or the Heywood interconnector.

Potential inertia shortfalls

Inertia shortfalls are now formally assessed and declared through the annual *NSCAS Report*[14] over a three-year outlook period. The latest modelling for that report indicates that projected levels of inertia are expected to remain above the South Australia portion of the system-wide inertia requirement.

As part of this assessment, AEMO deemed South Australia sufficiently likely to island on its own until PEC Stage 2 is commissioned and all necessary protection schemes are in place. As such, AEMO has assessed the region against its individual (islanded) secure levels of inertia. No shortfalls have been identified in the near term against these requirements.

Likelihood of islanding

Table 9 presents the criteria assessed when determining the likelihood of the South Australia inertia sub-network islanding from the remainder of the system.

[14] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.

Table 9 Assessment of the likelihood of South Australia islanding

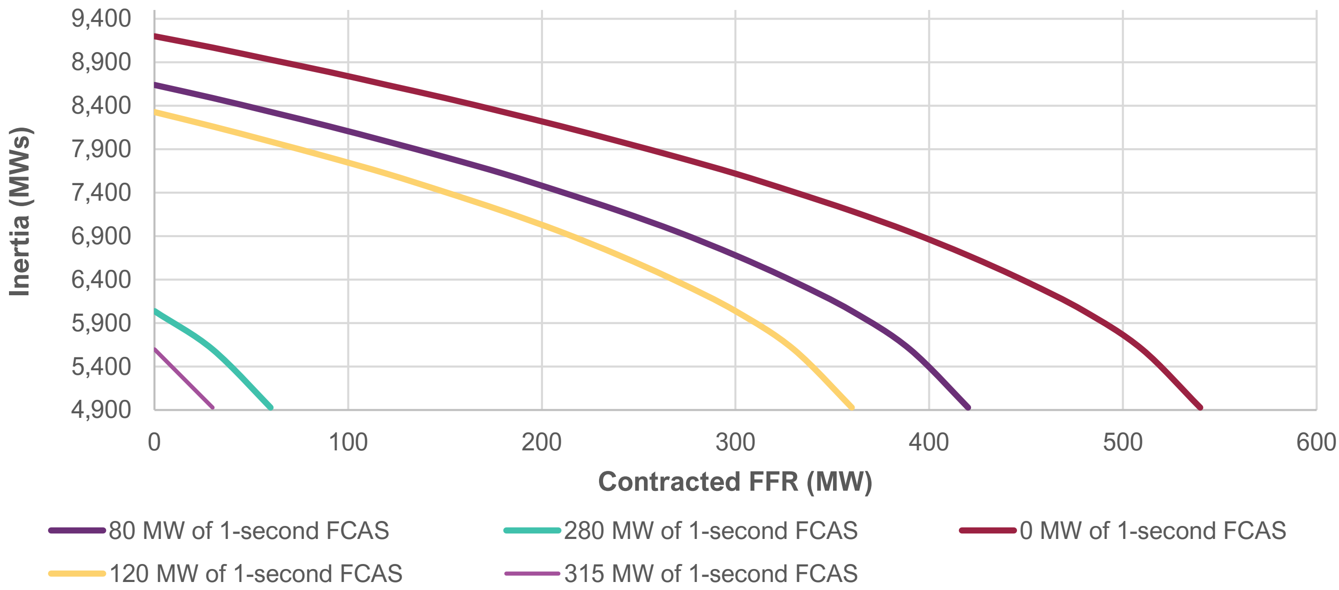
Criterion	South Australia
Inertia levels typically provided	6,200 MWs
Inertia levels compared to *secure inertia level*	*Inertia* levels forecast to be up to 1,200 MWs below the *secure inertia level* 81% of the time in FY2027, and approximately 74% of the time by FY2028.
Inertia sub-network allocation	4,300 MWs
Existing interconnections	One 275 kV AC double-circuit to Victoria. One DC link to Victoria.
Future interconnections and status	PEC: 330 kV double-circuit to New South Wales (Stage 1: 2024, Stage 2: 2027).
History of islanding	November 2022 March 2020 January 2020 November 2019 August 2018 December 2016 September 2016 November 2015
Applicable control schemes	TBC
Likelihood of islanding after contingency event	Plausible until PEC Stage 2 is commissioned.

Cooptimisation with contracted FFR and 1-Second FCAS

In addition to the *inertia requirements* presented above, Figure 4 defines a set of operating points that would each ensure the system remains in a satisfactory frequency operating state, following a credible contingency event.

The curves are intended to provide flexibility in the solutions used to address a declared shortfall. For example, an operating point below the curve would indicate a shortfall. This could be remediated by procuring inertia (moving up), contracting FFR services (moving right), or by procuring both services (moving both up and right). The optimal mixture will depend on the size and timing of the shortfall, and the options available in the region.

Figure 4 Relationship between inertia and fast frequency response in South Australia



When determining *inertia requirements* in South Australia, AEMO used an operating point with no contracted FFR, and assumed 315 MW of 1-second FCAS, which is the amount of 1-second raise FCAS currently registered in South Australia. This is equivalent to 532 MW of contracted FFR[15]. Using this operating point reflects that during islanded operation, local FCAS prices are likely to incentivise capacity to become available.

Assuming a lower (or derated) value would increase obligations on the TNSP and require them to either contract with an equivalent amount of FFR outside the market, or procure other inertia services that reduce the demand for 1-second FCAS. In both cases, the amount of derating assumed becomes self fulfilling by reducing either the demand or available providers in the 1-second market.

AEMO expects that a TNSP should consider the latest amount of registered 1-second FCAS when procuring FFR or inertia services. AEMO will continue to review *inertia requirements* annually.

[15] See Section A1.4.1 for details on this translation.

3.4 Tasmania

- For Tasmania, AEMO did not identify any changes to *satisfactory* and *secure inertia levels*, nor to its classification as sufficiently likely to operate under islanded conditions.
- AEMO confirmed the previously identified inertia shortfalls in Tasmania remain in effect, with a magnitude of between 2,184 MWs and 2,710 MWs, from 2025-26 until the end of the horizon. TasNetworks has commercial agreements in place to manage this shortfall until 1 December 2025.

Table 10 provides a summary of the *inertia requirements* for Tasmania, including the satisfactory and secure levels of inertia when planning for islanded operation. Tasmania is not subject to the system-wide inertia requirement, so no allocation has been included.

Table 10 Tasmania *inertia requirements* from 2 December 2024 to 1 December 2034

Quantity	Value
Satisfactory inertia level	3,200 MWs
Secure inertia level	3,800 MWs
Likelihood of islanding	Likely (continuous)

Potential inertia shortfalls

Inertia shortfalls are now formally assessed and declared through the annual *NSCAS Report*[16] over a three-year outlook period. The latest modelling for that report indicates an inertia shortfall in Tasmania of between 2,184 MWs and 2,710 MWs from 2025-26 until the end of the horizon. TasNetworks have sufficient network support agreements in place until 1 December 2025, and longer-term remediation may be possible alongside their system strength remediation.

Likelihood of islanding

An assessment of the likelihood of Tasmania islanding is presented in Table 11.

Table 11 Assessment of the likelihood of Tasmania islanding

Criterion	Tasmania
Inertia levels typically provided	1,616 MWs[A]
Inertia levels compared to *secure inertia level*	*Inertia* levels forecast to be below the *secure inertia level* after existing system strength contracts expire on 1 December 2025.
Inertia sub-network allocation	Not applicable.
Existing interconnections	One DC link to Victoria.
Future interconnections and status	Project Marinus: Two DC links to Victoria (Stage 1: 2030, Stage 2: 2032).
History of islanding	No AC interconnection to mainland regions.
Applicable control schemes	Frequency Control System Protection Scheme (FCSPS).

[16] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.

Criterion	Tasmania
Likelihood of islanding after contingency event	Likely

A. After existing system strength contracts expire.

3.5 Victoria

- AEMO updated the *satisfactory* and *secure inertia levels* for Victoria based on the latest power system modelling inputs. AEMO also assessed Victoria as unlikely to island from the remainder of the power system, given its strong interconnection with neighbouring regions.
- The projected level of inertia is expected to fall below the *inertia sub-network allocation* for Victoria, however sufficient inertia is available to be shared from neighbouring regions. AEMO Victorian Planning (AVP) is required to ensure sufficient supplies are available to meet its entire portion of the system-wide requirement from 1 December 2027.

Table 12 provides a summary of the *inertia requirements* for Victoria, including the assumed levels of 1-second FCAS available, the satisfactory and secure levels of inertia when planning for islanded operation, and the regional allocation of the system-wide level.

Table 12 Victoria *inertia requirements* from 2 December 2024 to 1 December 2034

Quantity	Value
Assumed level of 1-second FCAS	400 MW
Satisfactory inertia level	13,700 MWs
Secure inertia level	15,400 MWs
Inertia sub-network allocation	11,800 MWs
Likelihood of islanding	Unlikely

Potential inertia shortfalls

Inertia shortfalls are now formally assessed and declared through the annual *NSCAS Report*[17] over a three-year outlook period. The latest modelling for that report indicates that projected levels of inertia are expected to remain below the Victorian portion of the system-wide inertia requirement, however sufficient inertia is available to be shared from neighbouring regions.

As part of that assessment, AEMO deemed Victoria as unlikely to island on its own[18] given its strong interconnection with neighbouring regions, so does not expect any shortalls against the the *satisfactory* or *secure inertia levels*.

Likelihood of islanding

Table 13 presents the criteria assessed when determining the likelihood of the Victorian inertia sub-network islanding from the remainder of the system.

[17] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.

[18] Historically AEMO has assessed a scenario where the NEM has separated with Victoria and South Australia forming an island. For completeness, AEMO has confirmed that no inertia shortfall exists for this scenario with updated inputs in 2024, however AEMO considers that the *system-wide inertia level* requirement assessment should supersede the need for this scenario in future.

Table 13 Assessment of the likelihood of Victoria islanding

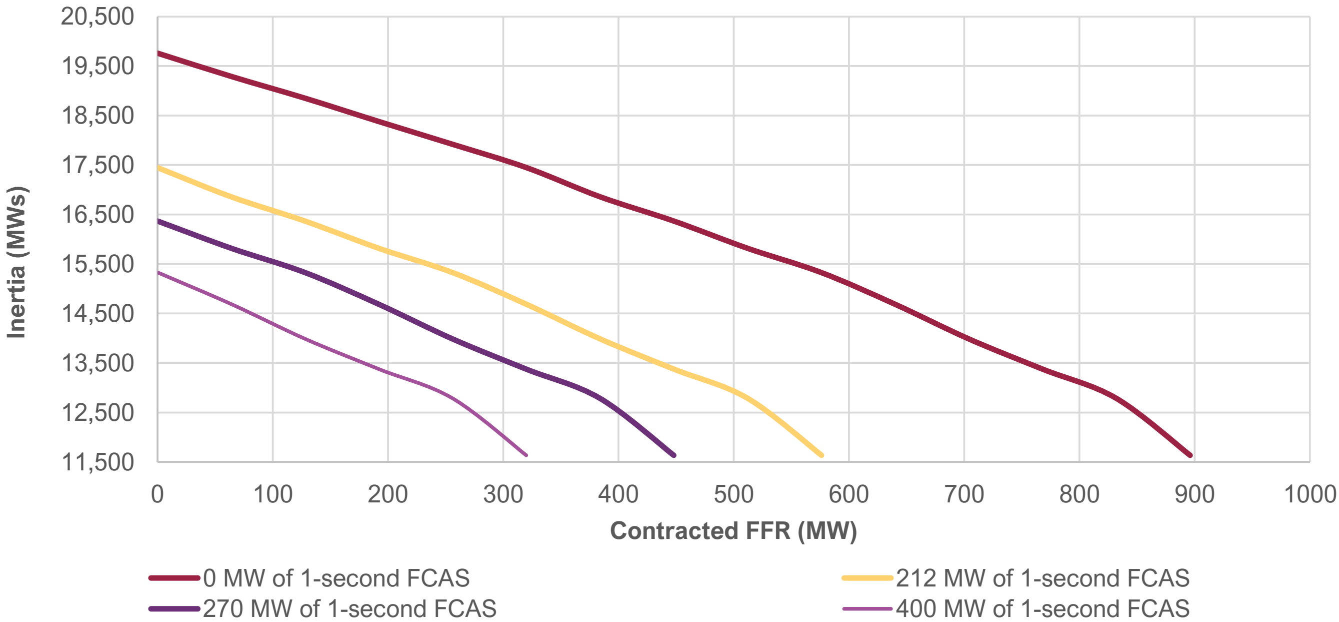
Criterion	Victoria
Inertia levels typically provided	8,337 MWs
Inertia levels compared to *secure inertia level*	*Inertia* levels forecast to be below the *secure inertia level* across the horizon.
Inertia sub-network allocation	11,800 MWs
Existing interconnections	One 220 kV, three 330 kV AC, and two 132 kV AC connections to New South Wales. One 275 kV AC double-circuit to South Australia. One DC link to South Australia. One DC link to Tasmania.
Future interconnections and status	PEC: 220 kV single-circuit to New South Wales (Stage 1: 2024, Stage 2: 2027). VNI West: 500 kV double-circuit to New South Wales (2029). Project Marinus: Two DC links to Tasmania (Stage 1: 2030, Stage 2: 2032)
History of islanding	N/A
Applicable control schemes	N/A
Likelihood of islanding after contingency event	Unlikely

Cooptimisation with contracted FFR and 1-Second FCAS

In addition to the *inertia requirements* presented above, Figure 5 defines a set of operating points that would each ensure the system remains in a satisfactory frequency operating state, following a credible contingency event.

The curves are intended to provide flexibility in the solutions used to address a declared shortfall. For example, an operating point below the curve would indicate a shortfall. This could be remediated by procuring inertia (moving up), contracting FFR services (moving right), or by procuring both services (moving both up and right). The optimal mixture will depend on the size and timing of the shortfall, and the options available in the region.

Figure 5 Relationship between inertia and fast frequency response in Victoria



When determining *inertia requirements* in Victoria, AEMO used an operating point with no contracted FFR, and assumed 400 MW of 1-second FCAS, which is the amount of 1-second raise FCAS currently registered in Victoria. This is equivalent to 620 MW of contracted FFR[19]. Using this operating point reflects that during islanded operation, local FCAS prices are likely to incentivise capacity to become available.

Assuming a lower (or derated) value would increase obligations on the TNSP and require them to either contract with an equivalent amount of FFR outside the market, or procure other inertia services that reduce the demand for 1-second FCAS. In both cases, the amount of derating assumed becomes self fulfilling by reducing either the demand or available providers in the 1-second market.

AEMO expects that a TNSP should consider the latest amount of registered 1-second FCAS when procuring FFR or inertia services. AEMO will continue to review *inertia requirements* annually.

[19] See Section A1.4.1 for details on this translation.

4 Next steps

This report updates AEMO's 10-year specification of *inertia requirements* in the NEM, building on the latest available power system modelling data and assumptions. TNSPs are responsible for procuring assets and services to meet the *inertia requirements* as specified in this report, by 1 December 2027. The requirements are presented in Table 14.

Table 14 Summary of *inertia requirements* from 2 December 2024 to 1 December 2034

Region	*Satisfactory inertia level* (MWs)	*Secure inertia level* (MWs)	*Inertia sub-network allocation* (MWs)
New South Wales	10,000	12,500	9,600
Queensland	12,000	13,700	10,500
South Australia	4,100	5,600	4,300
Tasmania	3,200	3,800	-
Victoria	13,700	15,400	11,800

AEMO also modelled the projected levels of inertia available across a three-year period from December 2024 to December 2027. These projections are used to identify inertia shortfalls as part of the 2024 *NSCAS Report*[20], and a summary of findings is presented in Table 15.

Table 15 Summary of projected inertia shortfalls

Region		Projected inertia shortfalls
	**New South Wales**	**No inertia shortfalls have been identified,** and Transgrid must ensure sufficient inertia is available to meet their full *inertia sub-network allocation* from 1 December 2027.
	**Queensland**	**The previously declared inertia shortfall in Queensland for islanded conditions decreased in magnitude to 256 MWs in 2027-28.** Remediation may be possible in parallel with the existing Powerlink System Strength RIT-T.
	**South Australia**	**No inertia shortfalls have been identified,** and the existing inertia shortfall has been addressed, primarily through additional registrations in the 1-second Frequency Control Ancillary Services (FCAS) market.
	**Tasmania**	**Existing inertia shortfalls have been confirmed for the region.** Sufficient network support agreements are in place until 1 December 2025, and longer-term remediation may be possible alongside system strength remediation.
	**Victoria**	**The projected level of inertia is expected to fall below the *inertia sub-network allocation* for Victoria, however sufficient inertia is available to be shared from neighbouring regions.** AVP must ensure sufficient inertia is available to meet their full *inertia sub-network allocation* from 1 December 2027.

[20] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.

A1. Inertia methodology and inputs

AEMO assessed *inertia requirements* in each region over a 10-year outlook period. This appendix provides an overview of the methodology and input data sources used to conduct these studies.

All assessments were conducted in accordance with the latest *Inertia Requirements Methodology*[21], and were based on the latest available data at the point where studies were initiated. In most cases, this data cut-off was 1 November 2024.

A1.1 Inertia sub-networks

AEMO must determine boundaries for inertia sub-networks, for which *inertia requirements* are assessed. AEMO may adjust these boundaries from time to time. Inertia sub-networks must be aligned within the boundaries of a NEM region, or wholly confined within a region[22].

AEMO has not made any adjustments to existing inertia sub-network boundaries, which correspond with the boundaries of NEM regions.

A1.2 Frequency control ancillary services

AEMO's assessment of inertia forecasts and shortfalls accounted for inertia impact from the FCAS markets[23] by assuming that registered participants in the raise and lower 1-second FCAS markets will be available to provide their maximum capability, if they can reasonably be expected to be enabled at the time when the *inertia requirements* will apply. While it may be considered ambitious to assume the entire 1-second FCAS fleet is available, AEMO considers this is offset by the fact that additional FCAS will be registered over time. Section A1.4.1 has more detail on how the new 1-second FCAS market was included.

A1.3 Calculating inertia requirements

Under National Electricity Rules (NER) 5.20B.2, AEMO assesses inertia shortfalls against three distinct levels of requirement:

- The *satisfactory inertia level*, 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.
- The *secure inertia level*, 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.

[21] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.

[22] NER 5.20B.1

[23] For information about the FCAS markets in the NEM, see https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services.

- The *system-wide inertia level*, being a mainland inertia required to operate the mainland regions of the interconnected NEM securely.
- *Inertia sub-network allocation*, being the portion of the *system-wide inertia level* allocated to that inertia sub-network.

In determining these requirements, AEMO considers the largest relevant credible contingency event, any consequential demand-side response, the levels of FCAS available, and AEMO's operational procedures for periods where regions are islanded or at risk of islanding.

In 2023, AEMO reviewed the *secure* and *satisfactory level of inertia requirements* for South Australia, Queensland and Victoria. In 2024, these requirements were also reviewed for New South Wales to accommodate the following changes:

- Updated distributed PV/load models which also capture momentary cessation characteristics as well as overall disconnection after a fault.
- New 1-second FCAS market which can take the place of contracted FFR in inertia.
- New frequency operating standard (FOS) including 1 hertz per second (Hz/s) rate of change of frequency (RoCoF) for islanded conditions for NEM mainland and 3 Hz/s for Tasmania.
- More large-scale inverter-based resources (IBR) susceptible to fault ride-through[24].

A two-stage approach is used to determine the new *inertia requirements*:

- Stage 1 uses PSS®E dynamic studies to determine the critical contingencies and the impact of voltage sensitivity phenomenon including large scale IBR fault ride through, momentary distributed PV cessation, and load response.
- Stage 2 uses a Single Mass Model (SMM) to perform multiple simulations where the inertia is varied. This is tuned to include the impact of voltage sensitive phenomenon.

Success criteria

The following conditions must be met for the power system or islanded inertia sub-network to be considered as having sufficient inertia:

- Following a credible contingency event for an islanded region in the mainland, or for the interconnected mainland system, the RoCoF must not be greater than 1 Hz/s measured over any 500 milliseconds (ms) period.
- Following a credible contingency event for an islanded Tasmania, the RoCoF must not be greater than 3 Hz/s measured over any 250 ms period.

The tables below summarise the critical frequency outcomes AEMO measured against in the new *inertia requirements* study. Further information on the new FOS and definitions can be found on the AEMC website[25].

[24] During a fault, IBR may cease real power production for a short period of time, and have a period of active power recovery (typically around 100-300 ms).

[25] At https://www.aemc.gov.au/news-centre/media-releases/final-determination-frequency-operating-standard#:~:text=The%20revised%20FOS%20will%20come,which%20provide%20fast%20frequency%20response.

Table 16 Mainland system frequency outcomes for an island within the mainland other than during system restoration.

Condition	Containment band (Hz)	Stabilisation band (Hz)	Recovery band (Hz)
No contingency event or load event	49.5 – 50.5	N/A	
Generation event, load event or network event	49.0 – 51.0	49.5 – 50.5 within 5 minutes	

Table 17 Tasmania system frequency outcomes where an island is formed within Tasmania

Condition	Containment band (Hz)	Stabilisation band (Hz)	Recovery band (Hz)
No contingency event or load event	49.0 – 51.0	N/A	
Generation event, load event or network event	48.0 – 52.0	49.0 – 51.0 within 10 minutes	

Table 18 Mainland system frequency outcomes for an interconnected system

Condition	Containment band (Hz)	Stabilisation band (Hz)	Recovery band (Hz)
No contingency event or load event	49.75 – 50.25	49.85 – 50.15 within 5 minutes	
Generation event or load event	49.5 – 50.5	49.85 – 50.15 within 5 minutes	

Following a contingency, the power system or inertia sub-network must be able to find a new stable operating point. This includes:

- Voltages in the high voltage transmission network returned to nominal voltages.
- No automatic load (under frequency load shedding (UFLS)) or generation shedding (over frequency generation shedding (OFGS)) occurred.
- In-service transmission elements remain connected and returned to new steady-state conditions, except for plant included in any special control or protection scheme.
- All in-service generation remain connected and returned to new steady-state conditions, except generators that are part of the contingency considered or included in any special control or protection scheme.

Stage 1: PSS®E dynamic studies

The critical contingencies considered in the PSS®E dynamic studies include the loss of a generating unit, system or load that results in the highest RoCoF in the inertia sub-network. The loss of a generating unit or system can be the result of a fault on a network element and the subsequent disconnection of generation.

An important change in the methodology of this new *inertia requirements* study is the inclusion of AEMO's updated distributed PV and composite load models[26] to accurately represent load and distributed PV behaviours during power system disturbances.

AEMO's historical approach to load modelling is to use a ZIP load model, which is a polynomial static load model with real (Np) and reactive power (Nq) voltage indexes of 1.0 and 3.0 respectively. Recently, AEMO has developed

[26] AEMO. PSS®E models for load and distributed PV in the NEM. November 2022. At https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en.

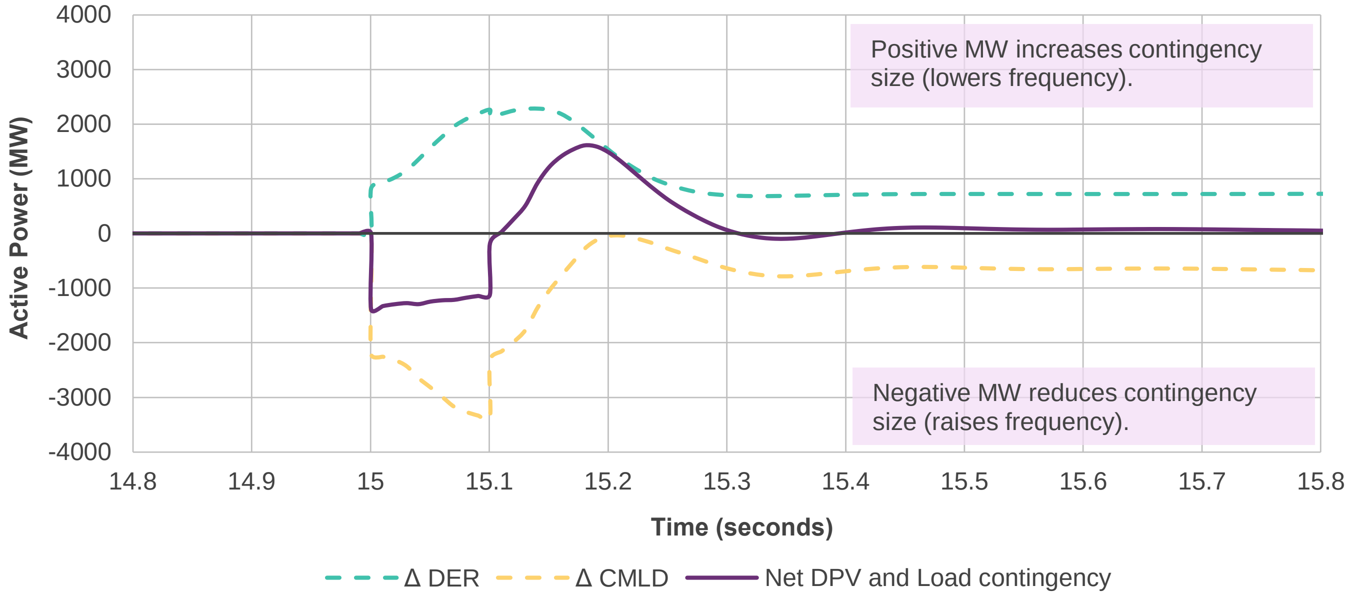
a composite load model (CMLD) which incorporates both static and dynamic load model components. The CMLD provides a more accurate representation of voltage and frequency responses of different types of load and its tripping behaviour.

Distributed PV was not modelled in previous annual inertia studies. When the effects of a distributed PV trip were to be tested, it was represented by a step increase in metropolitan loads. The new model captures the voltage, frequency, and RoCoF response of distributed PV, providing an accurate representation of distributed PV momentary cessation and distributed PV tripping behaviour.

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

Figure 6 below shows the impact of distributed PV, load, and a combination of both on the contingency size. After fault clearance, the slower recovery[27] of distributed PV compared to load resulted in an increase in contingency size by approximately 1,500 MW.

Figure 6 Net load and distributed PV response to Tarong North 180 MW contingency in an islanded Queensland

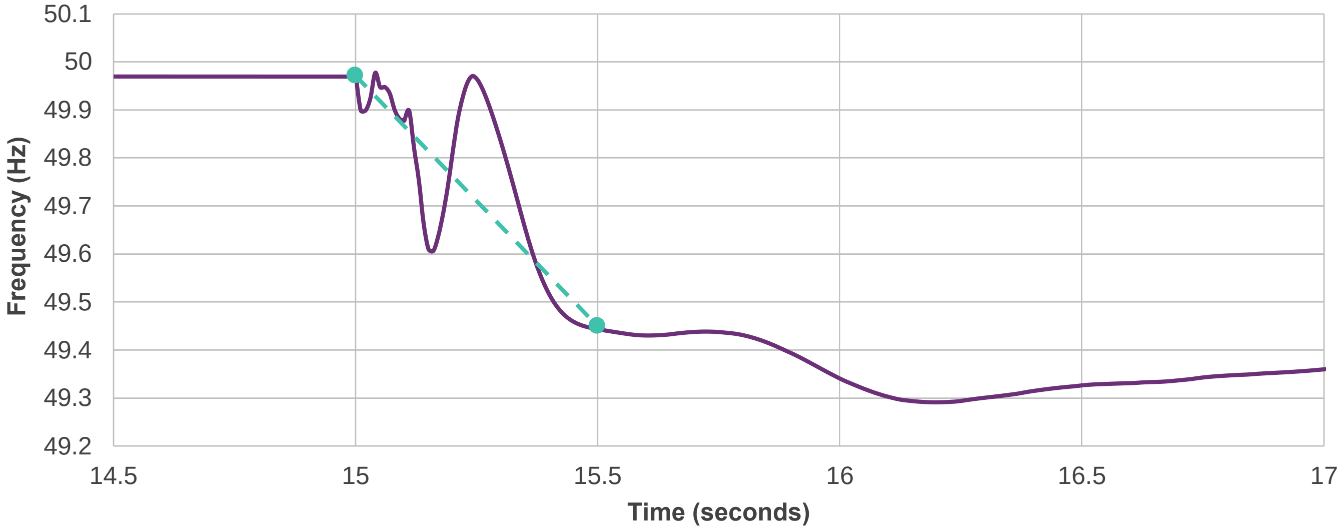


In Stage 1 studies, FFR is assumed to be wholly provided by existing batteries in the network and their response is modelled on their provided PSS®E models. When additional FFR capability was to be modelled, committed projects where appropriate PSS®E models were available were used.

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

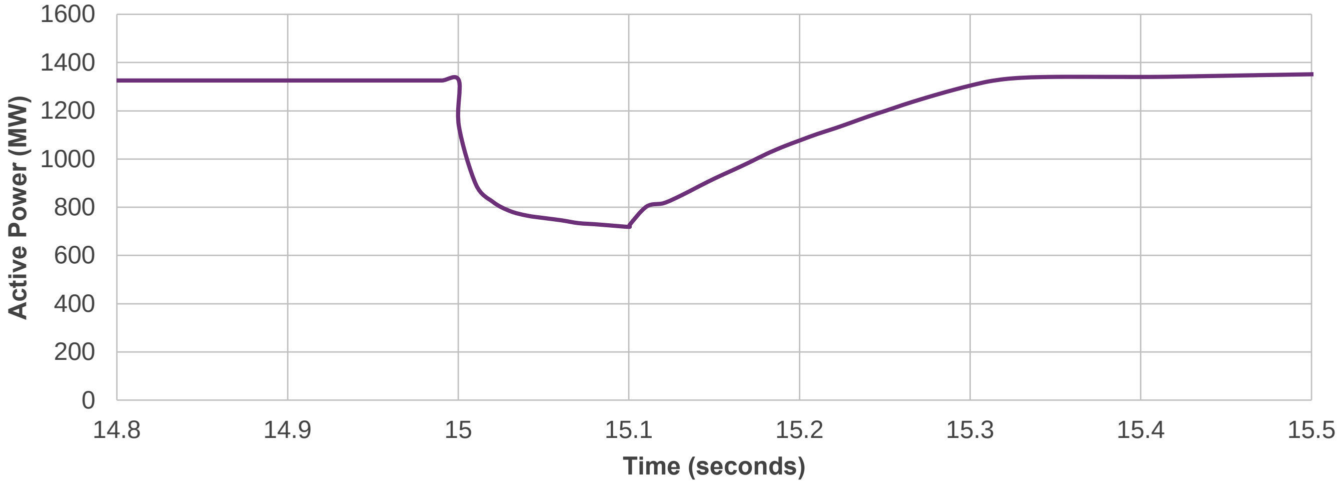
Furthermore, the new FOS specifies a RoCoF limit of 1 Hz/s measured over any 500 ms period for either the interconnected mainland system or an islanded condition in the NEM mainland, and 3 Hz/s measured over any 250 ms period for Tasmania. The RoCoF is measured by averaging the frequency at all buses with voltage greater than or equal to 275 kV, and short-term transients are disregarded. This can be seen in Figure 7.

Figure 7 Rate of change of frequency measurement over 500 ms period



The installed capacities of large scale IBR have increased over recent years. During faults, these IBR may enter fault ride-through mode which involves reducing active power output to inject reactive power for voltage support. The fault ride-through characteristics of large scale IBR will impact frequency outcomes as the reduction in generation can be significant. Figure 8 shows the total solar farm generation in the above Queensland study. The total solar farm active power output reduced by approximately 46%, which equates to 607 MW.

Figure 8 Total solar farm generation in a Queensland islanded case under the Tarong North contingency



Stage 2: Single Mass Model

The SMM represents multiple generating units with various inertia as a single generating unit with equivalent inertia, and effectively solves the energy balance of the power system over time given the relationship between real power, frequency and inertia. The SMM is based on the swing equation of the power system and iteratively solves a set of equations for frequency to model the behaviour of the system. In Stage 1, the IBR fault ride-through, load response, and distributed PV response to a given contingency under a particular NEM condition are derived from the PSS®E dynamic studies.

Given that the SMM does not model concepts such as network topology or voltage, the output data from the PSS®E studies in Stage 1 are used to modify the SMM to account for load, distributed PV and IBR responses to contingencies. The correct functioning of these responses, as well as all success criteria listed above, need to be checked during the PSS®E dynamic studies to ensure that the SMM can provide accurate frequency results. When solving the SMM in Stage 2, these responses are represented as additional contingencies with regards to the swing equation. The output data from Stage 1 is used to tune the SMM representation to ensure that the energy delivered across the first 500 ms after the fault is equal across PSS®E and SMM. As these responses are considered to be additional contingencies in the SMM, a positive MW change indicates a loss of MW generation or an increase in contingency size. The figures below show examples of how the IBR fault ride-through, distributed PV, and load responses are simplified into linear representations and modelled in the SMM.

Figure 9 Example inverter-based resources fault ride-through representation in Single Mass Model

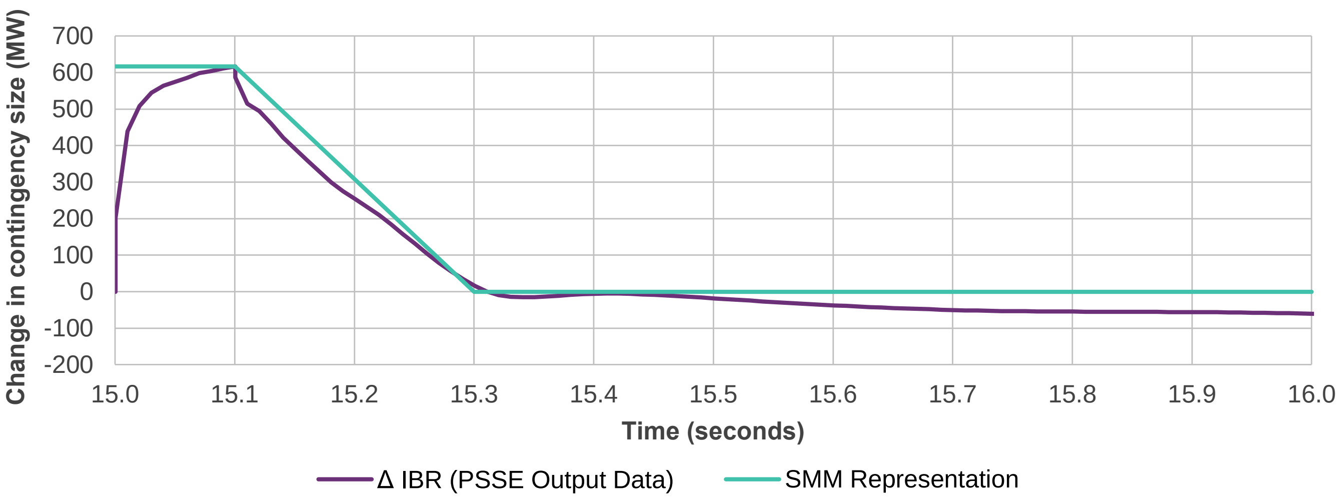


Figure 10 Example distributed PV momentary cessation and trip representation in Single Mass Model

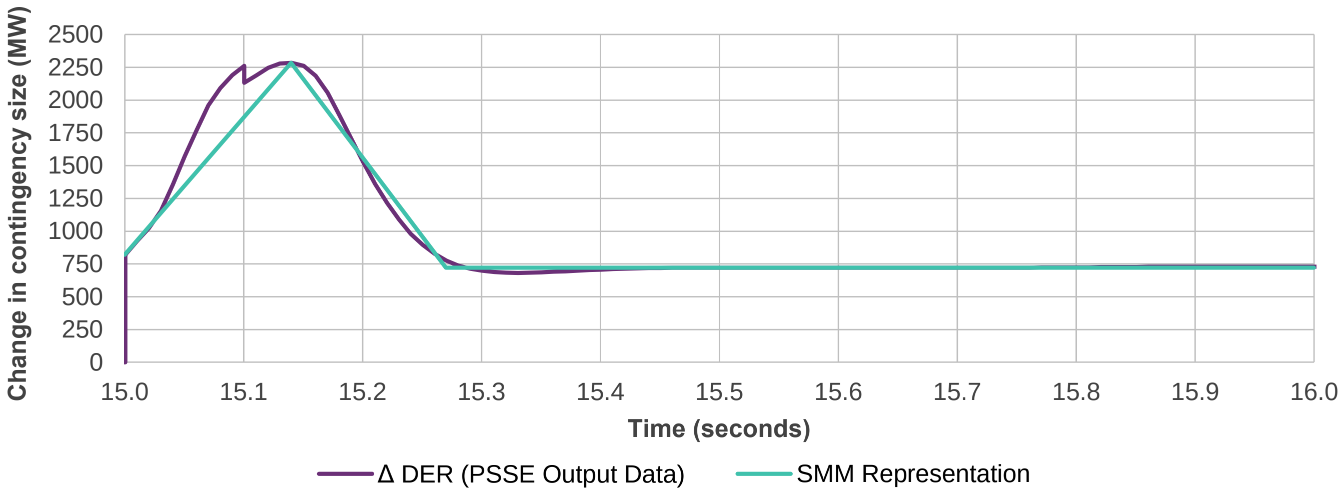
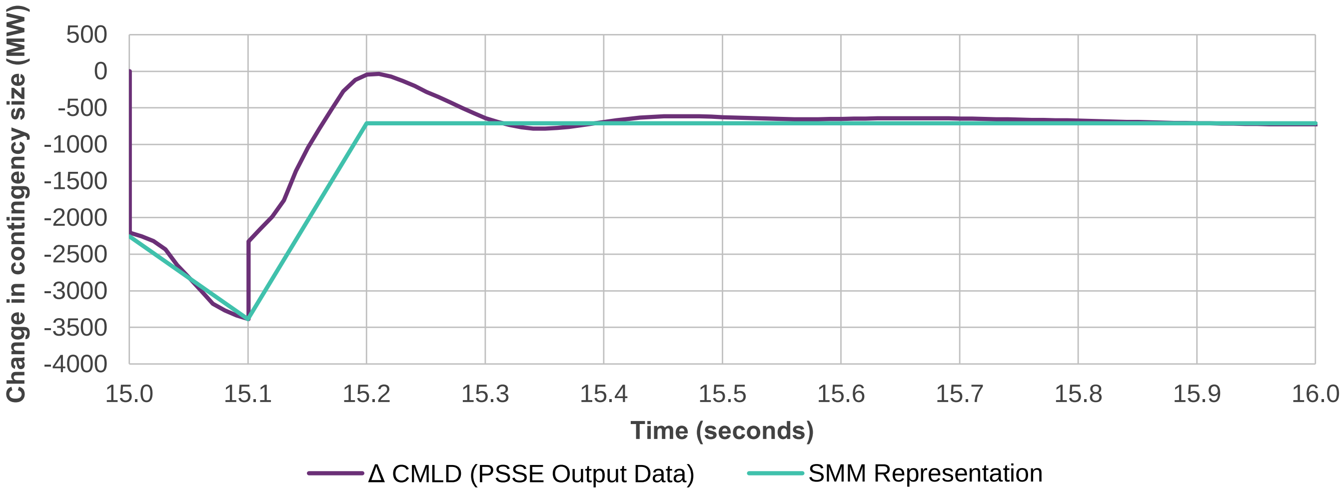


Figure 11 Example load undervoltage response and trip representation in Single Mass Model

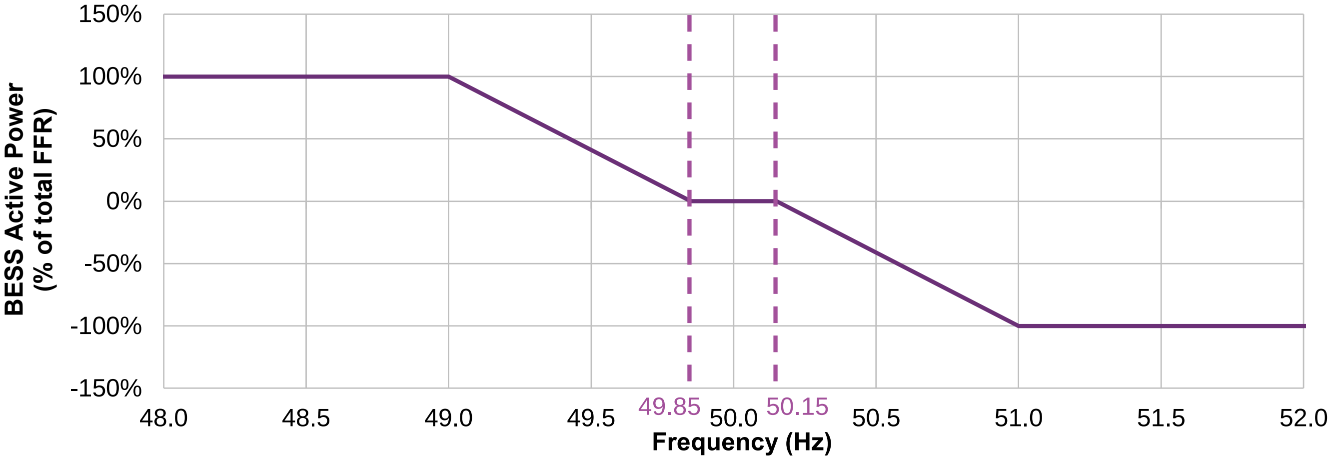


The SMM is tuned by first calculating the areas under the SMM linear graphs and the PSS®E output data for the first 500 ms after the fault. The MW values used in the SMM representation, except for the trip amounts, are then scaled by the ratio PSS®E area : SMM area until the SMM area matches the PSS®E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

In the SMM, the BESS provides a frequency-active power droop[28] response, as shown in Figure 12 below. As frequency drops from 49.85 Hz to 49.0 Hz, the BESS active power output increases linearly from 0% to 100% of total FFR. Similarly, as frequency increases from 50.15 Hz to 51.0 Hz, the BESS active power output drops linearly from 0% to -100% of total FFR.

[28] This droop response reflects the physical response of BESS with frequency droop controllers. This response is typically faster than the response which is represented by ideal triangles in the FCAS markets. In addition, these plants typically have greater MW capability than its registered R1 and L1 capabilities.

Figure 12 Single Mass Model default battery energy storage system droop response in an islanded mainland region



A1.4 Defining inertia requirements as a function of fast frequency response

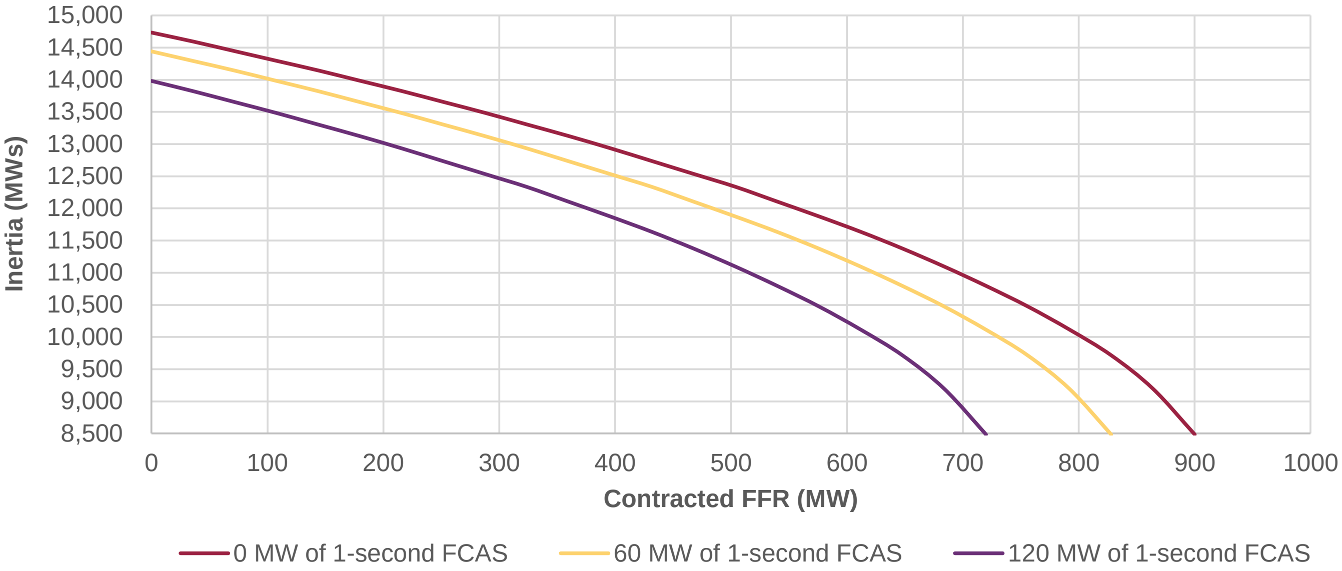
The secure operating level of inertia for a region is sensitive to the FFR capability available. AEMO does not model FFR as providing inertia explicitly, and instead accounts for FFR through adjustments to the *inertia requirements* themselves.

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

For example the relationship between inertia and FFR capability for Queensland is presented in Figure 13, where the curve defines a set of operating points that would deliver a secure level of frequency control, sufficient to meet RoCoF requirements for all credible contingency events in the region. Note, to validate the requirement, PSS®E is used to check against the other success criteria such as voltage.

The curve divides the space into acceptable and unacceptable regions and provides an opportunity for flexible solutions in addressing any declared shortfalls. For example, a projected operating point that falls below the curve (shortfall), could be returned to the curve (remediated) by moving it up (procuring inertia), or right (procuring FFR), or both up and right (procuring both inertia and FFR). The optimal mixture of remediation services will depend on both the size and timing of the shortfall.

Figure 13 Relationship between inertia and fast frequency response in Queensland



A1.4.1 How the FFR capability translates to the 1-second FCAS market

For this year, services provided by 1-second FCAS markets have been included in the modelling, however it is important to understand that for BESS providing 1-second FCAS, there is a definitional distinction between their total FFR capability, and the MW capacity registered in the 1-second FCAS market:

- FFR capability represents the total physical response available from the plant due to its nameplate capacity and control systems, typically a frequency droop controller.
- In contrast, registered 1-second FCAS capacity is based on the *peak active power* in response to a 0.5 Hz change in frequency, which is almost always less than the maximum FFR capability of a BESS.

Peak active power is a term defined in the market ancillary service specification, being the change in power due to its droop setting at the lower or raise reference frequency[29]. For a typical droop setting of 1.7%, this works out as a 1-second FCAS capacity of about 57% of FFR capability[30].

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

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

[29] Lower reference frequency and raise reference frequency are 50.5 Hz and 49.5 Hz respectively (for NEM mainland).

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

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

Worked example

A region with the following 1-second FCAS registrations has approximately 92 MW of FFR capability:

Station Name	Bid Type	Registered Max Cap (MW)	Controller	Calculated FFR
BESS 1	Raise1sec	40	Droop (1.7%)	40/0.57 = 70
Switched Load A	Raise1sec	10	Switched	10
Switched Load B	Raise1sec	12	Switched	12
			Total FFR	**92**

A1.5 Likelihood of combined regions islanding

In addition to its usual consideration of the likelihood of inertia sub-networks islanding individually, historically AEMO has conducted additional inertia assessments of cases where two or more inertia sub-networks are at risk of forming a combined island. These assessments were performed for a New South Wales (excluding south-western New South Wales) and Queensland island, and a South Australia and Victoria (including south-western New South Wales) island (Tasmania is excluded as it provides no inertial support to Victoria).

While not presented in the 2024 *Inertia Report*[31], this assessment has been conducted and confirmed no shortfalls exist under this scenario. AEMO notes that with the introduction of the new system-wide level of inertia requirement, this type of assessment is no longer required, as all mainland NEM regions will be required to maintain sufficient inertia to support their network.

[31] Shortfall assessments are now in the 2024 NSCAS Report, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.