Evaluating market designs for inertia services

A report for the Australian Energy Market Commission

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Executive summary

The National Electricity Market (NEM) is expecting to experience a significant decline in system inertia as traditional synchronous generation is progressively replaced by renewable energy sources. Inertia, which has historically been provided as a byproduct of synchronous generation, plays a crucial role in maintaining frequency stability by resisting rapid changes in system frequency following disturbances. In response to these challenges, the Australian Energy Market Commission (AEMC) published new rules in March 2024 expanding the frameworks for procuring inertia through long-term contracts with Transmission Network Service Providers (TNSPs).

While these new arrangements provide a foundation for maintaining minimum levels of inertia, questions remain about whether alternative market designs might more efficiently facilitate both investment in and provision of an optimal level of inertia services.

Within this context, the AEMC asked HoustonKemp to evaluate the economic case for different market arrangements for inertia provision, with a particular focus on whether a spot market mechanism could deliver better outcomes than the current contract-based approach.

Our approach to this task has combined rigorous economic analysis with extensive stakeholder engagement through the AEMC's Technical Working Group. This engagement has been crucial in understanding both the technical requirements for providing inertia services and the practical challenges faced by different technologies and market participants. Drawing on these insights, we have developed a comprehensive framework for evaluating alternative market designs and undertaken detailed quantitative analysis to assess the potential economic benefits that could be realised through different market arrangements.

Importantly, our analysis recognises that different types of inertia services may warrant different market approaches. The inertia services that we have focused on are:

- minimum inertia requirements (ie, minimum levels that are set by AEMO in planning timeframes); and
- incremental inertia (ie, inertia services above the level available through energy dispatch in operational timeframes), which consists of two types:
  - additional inertia – inertia above minimum levels; and
  - operational top-up inertia – inertia that addresses an operational shortfall with respect to the minimum level that arises during operational timeframes.

Developing a framework to evaluate market designs for inertia

Our evaluation of potential market designs for inertia services begins with a first principles economic analysis that recognises the fundamental role of markets in facilitating efficient exchange between buyers and sellers. This foundational approach allows us to systematically assess how different market arrangements might accommodate the unique characteristics of inertia services while promoting economic efficiency.

The framework we have developed considers three key dimensions of economic efficiency that should be promoted through market design. First, allocative efficiency ensures resources are directed to their most valuable use, particularly important given the operational trade-offs between inertia and other frequency control services. Second, productive efficiency focuses on delivering services at lowest cost, critical for minimising the long-term costs to consumers. Third, dynamic efficiency promotes innovation and cost reduction over time, essential given the likely evolution of technologies capable of providing inertia.

When evaluating which market design might best facilitate efficient outcomes, we identified five key characteristics that influence the effectiveness of different market arrangements:

- the **nature of the service** itself – specifically whether it can be clearly defined and the extent to which requirements may evolve over time;
- **opportunities for efficiency gains** through technological innovation and optimal combinations of different supply technologies;
- the **economic consequences** of under or over supplying inertia services;
- the **need for investment certainty** to incentivise development of inertia-providing technologies; and
- the **likely extent of competition** in supplying inertia services.

These characteristics can point toward different preferred market designs. For example, services with severe consequences from undersupply may warrant arrangements that prioritise availability over short-term cost optimisation. Similarly, services requiring substantial upfront investment may benefit from designs that provide greater revenue certainty.

Importantly, our framework recognises that different categories of inertia services may warrant different market approaches. The characteristics and implications for market design differ significantly between minimum inertia requirements in a planning timeframe, which are essential for maintaining system security, and incremental inertia services that allow for more flexible provision based on economic trade-offs. This suggests value in evaluating market designs separately for these distinct categories of service.

Which market design is preferred for meeting minimum inertia requirements?

Our analysis of market designs for minimum inertia requirements in a planning timeframe reveals a fundamental tension between ensuring system security and promoting long-term efficiency. The requirement to maintain minimum levels of inertia is essential for power system stability, with potentially severe economic consequences if these requirements are not met. This suggests a strong preference for market arrangements that prioritise certainty of supply, particularly to ensure there is sufficient inertia capacity available to meet minimum operational inertial requirements.

This preference stems particularly from our assessment that the **economic consequences of under supply** are potentially significant for consumers. A shortfall in minimum inertia requirements could lead to system instability, cascading outages, or even widespread blackouts. These outcomes would impose substantial costs on electricity consumers and the broader economy through both direct interruption costs and flow-on effects to economic activity. While oversupply of minimum inertia involves the potential for some increased costs to consumers, these costs are likely to be relatively modest compared to the potential economic damage from undersupply.

The provision of sufficient inertia capacity to satisfy minimum inertia requirements may require capital investment in long-lived assets. This means there is likely to be a **need for investment certainty** to address market risks for investors. Synchronous condensers with flywheels, grid-forming batteries and repurposed synchronous generators are examples of technologies that require upfront investment to ensure continuous availability of inertia. This creates a need for investors to have reasonable certainty over future revenues, particularly given that some of these investments are largely specific to providing system security services.

We find that the **extent of competition** between alternative technologies and providers is likely to be sufficient to mitigate concerns regarding market power, even in a spot market environment. The ability of different technologies to serve as effective substitutes, combined with relatively low barriers to entry for some technologies like grid-forming batteries, means that individual suppliers would likely face competitive constraints in their bidding behaviour. However, this characteristic alone is not definitive for a choice of market design.

The key challenge for market design is establishing frameworks that maintain incentives for technological development and innovation over the medium to long term to create **opportunities for efficiency gains**, while ensuring efficient deployment of currently available technologies in the short term. In examining potential market design options, we observe that:

- in the near term, adding flywheels to synchronous condensers that TNSPs currently expect to implement to meet system strength requirements likely represents the least cost source of minimum inertia;
- the incremental cost of adding inertia capability to these assets through flywheels during initial construction is relatively low;
- more substantial efficiency gains may emerge over a longer horizon as alternative technologies to provide inertia mature and become more readily available in the NEM; and
- continuous price signals from a spot market to meet minimum inertia requirements may not deliver material productive or allocative efficiency gains given current technological and cost characteristics, particularly in the near term.

The asymmetric nature of economic costs likely favours market arrangements that prioritise certainty of supply over short-term cost optimisation. We therefore conclude that a medium to long-term contracting framework likely represents the most appropriate market design for ensuring that there is sufficient inertia capacity available to meet minimum inertia operational requirements. This approach provides the certainty needed to support efficient investment while maintaining system security, particularly in the near term.

That said, in our opinion contract durations for supplying minimum inertia should be carefully calibrated to align with expected technological development cycles, thereby preserving competitive pressure from emerging technologies in future procurement rounds while providing sufficient revenue certainty for current investments.

Which market design is preferred for operational top-up and additional inertia services?

The technical and economic characteristics of operational top-up and additional inertia services differ fundamentally from minimum inertia in a planning timeframe, creating distinct considerations for market design.

Above minimum operational levels, inertia can be operationally substituted with other frequency control services, particularly fast frequency response (FFR). This substitutability, combined with different consequences of under-provision, suggests potential benefits from more dynamic market arrangements.

Operational top-up inertia services can potentially substitute in an operational timeframe for other mechanisms such as changes to contingency or directions, to address operational shortfalls in inertia that may arise from the energy dispatch process.

The business case for investing in technologies to provide operational top-up and additional inertia services differs materially from that required for minimum inertia. We expect that operational top-up and additional inertia services will primarily be provided opportunistically by existing or planned inertia-capable technologies, rather than through dedicated investment in new facilities. This could include:

- synchronous generators varying their commitment decisions;
- batteries with grid-forming capabilities managing their headroom/foot-room; and
- new technologies as they emerge and become commercially viable.

The market for incremental inertia services is therefore likely to feature robust competition due to both direct competition between inertia providers and indirect competition from substitute services. This competitive dynamic means that any attempt to exercise market power would likely be constrained by the ability to switch between alternative technologies or frequency control services to maintain system security.

A spot market for incremental inertia services could theoretically deliver benefits through:

- dynamic trade-offs between inertia and FFR based on relative costs;

- more efficient unit commitment decisions by synchronous generators;
- reduced reliance on directions and other intervention mechanisms; and
- innovation in how grid-forming batteries and other technologies provide frequency response.

However, the size of these benefits will depend critically on:

- the cost differential between incremental inertia and frequency control services;
- the transaction costs associated with establishing and operating the market mechanism;
- the ability of the market design to support efficient co-optimisation between services; and
- the development of systems capable of operationalising technical trade-offs between services.

Importantly, neither under nor over supply of incremental inertia services threatens system security, since minimum inertia requirements are managed separately. This means that the economic consequences of temporary imbalances are likely to be relatively modest and self-correcting through normal market processes, unlike the severe consequences of undersupply for minimum inertia requirements in a planning timeframe. This does not imply that there may not be opportunities to deliver economic benefits from more optimal supply of incremental inertia services, which we have considered further in this report.

Our assessment suggests that neither a spot market nor a long-term contract market holds a clear theoretical advantage for incremental inertia services. The key characteristics we have evaluated – including service definition, competition, efficiency opportunities, and consequences of imbalances – do not decisively favour one market design over the other. This implies that the choice of market design should be primarily driven by practical considerations, particularly whether the expected market benefits exceed the costs of implementation for any given design.

Quantification of the benefits of operational top-up and additional inertia services

Our analysis evaluated four potential sources of benefit from providing incremental inertia services in the NEM. These benefits arise from optimising inertia provision to reduce system costs, with each benefit category reflecting different operational circumstances where operational top-up and additional inertia could deliver economic value.

Our analysis suggests that the range of benefits associated with providing operational top-up and additional inertia services in the NEM across the four benefit categories is as follows:[1]

- for additional inertia services:
  - the '*inertia – FFR optimisation*' benefit ranges from $7.7 million in 2024 to $30 million in 2033 at the upper end;
  - the '*RoCoF constraint alleviation*' benefit ranges from $2 to $20 per MWs of additional inertia in South Australia, and from $5 to $355 per MWs of additional inertia in Tasmania during low inertia periods;
- for operational top-up inertia services:
  - the '*contingency size change*' benefit ranges from $0.7 million and $7.2 million per year; and
  - the '*directions reduction*' benefit averages to $1.8 million per direction avoided.

The analysis suggests that:

[1] All values are expressed in 2024 dollar terms.

- the benefits from optimising FFR with additional inertia are likely to be currently low, but might increase over time as the need for 1-second FCAS otherwise rises due to the progressive exit of synchronous generation from the market that reduces the 'natural' provision of inertia through energy dispatch;
- the most significant potential benefit arises from potentially avoiding the need for AEMO to issue directions to synchronous generators during periods of low operational inertia, although further consideration is needed to determine whether a mechanism for increasing operational top-up inertia is best placed to lower the need for directions;
- the benefits from increasing inertia in South Australia and Tasmania are like to vary over a relative wide range, depending on the extent to which low levels of inertia in these regions constrain down more efficient generation resources in the NEM in order to manage RoCoF in operational timeframes; and
- the benefits resulting from avoiding contingency size changes are likely to vary over a wide range depending on how often contingency sizes are changed to address operational inertia shortfalls in the future.

There is significant uncertainty about the costs for implementing a spot market for incremental inertia services. Practically, such a market would require investment in market systems and processes, and ongoing costs for both AEMO and market participants. We have roughly estimated that these costs may be as high as $20 million, with ongoing costs are likely to be a further $1 to $2 million each year for AEMO and other market participants.

Looking ahead, while there are clear benefits from introducing incremental inertia services in the NEM, our analysis suggests these benefits may not be large in the near term. However, these benefits might increase, potentially significantly, as synchronous inertia available to the system declines over time.

That said, should the costs of implementing a market mechanism be lower than our rough cost estimates, or contingency size changes or directions start to emerge as a significant market problem, or 1 second FCAS costs rise significantly in the future, there may be a greater case for developing a spot market for incremental inertia services.

Summary of conclusions

Our evaluation of market designs for inertia services concludes that different approaches are needed for different categories of inertia. The characteristics and consequences of under-provision differ markedly between minimum inertia requirements, which are essential for system security, and operational top-up and additional inertia services that can be operationally traded off against other frequency control services and assist with avoiding other market interventions to deliver minimum operational inertia needs.

For minimum inertia requirements in a planning timeframe, we find that a medium to long-term contracting framework remains the most appropriate market design. This conclusion reflects the need for investment certainty to support capital-intensive technologies, the severe economic consequences that could arise from under-provision of inertia capacity to the market, and the current opportunity to leverage system strength investments efficiently. However, contract durations should be carefully calibrated to maintain incentives for innovation and technological development.

While our analysis supports a conclusion that there are benefits from introducing operational top-up and additional inertia services in the NEM, these benefits may not be large in the near term. That said, the value proposition could strengthen over time as conventional power plants retire and naturally occurring inertia from regular power generation declines. The current uncertainty about inertia needs will likely be resolved as the capacity of synchronous condenser investment to address system strength becomes clearer and the renewable generation transition continues.

A thorough assessment of both the implementation and operational costs of an inertia spot market, combined with projections of how 1-second raise FCAS service costs may increase as system inertia decreases, will further inform whether pursuing an inertia spot market is worthwhile at this time. This analysis will also help to determine whether the market benefits are likely to outweigh the costs, and so the best timing for introducing such a market mechanism.

1. Introduction

The National Electricity Market (NEM) is experiencing a decline in inertia as the power system transitions towards decarbonisation. Inertia, crucial for maintaining frequency stability, has traditionally been a by-product of electricity generation from synchronous generators such as coal and gas power plants. As these generators are phased out in favour of cleaner energy sources, the provision of inertia is decreasing, posing challenges for grid stability.

This reduction in inertia is expected to lead to increased difficulties in maintaining frequency stability across the NEM. As a result, there is a need to rely more on fast frequency response (FFR) services to ensure grid reliability in this evolving energy landscape. Policymakers and the Australian Energy Market Operator (AEMO) are addressing this problem through various strategies. Currently, AEMO identifies inertia shortfalls and transmission network service providers (TNSPs) are required to address shortfalls by procuring inertia services, including through contracts with synchronous generators, contracts with grid-forming batteries and/or through acquisition of synchronous condensers. Additionally, AEMO is exploring the extent to which new technologies, including grid-forming batteries, can be relied upon to provide inertia for the grid.

In response to these challenges, the Australian Energy Market Commission (AEMC) published new rules governing inertia in March 2024.[2] These rules, part of the *Improving Security Frameworks for the Energy Transition* (ISF) rule change, expand the existing inertia procurement framework. This amendment provides AEMO with additional tools to manage inertia in the NEM throughout the energy transition period and beyond.

Following its consideration of long-term inertia procurement in the ISF rule change, the AEMC is now considering how inertia should be provided in operational timeframes.[3] It received a rule change request from the Australian Energy Council (AEC) in March 2023 raising concerns that the current methods of procuring inertia – through contracts and directions – may not be achieving efficient levels of investment in and provision of inertia services. The lack of a market-based mechanism potentially hinders optimal resource allocation and investment decisions.

In response to these comments from stakeholders, the AEMC is investigating whether an inertia spot market would better promote the NEO and has asked HoustonKemp to evaluate the economic case for alternative market designs for inertia services.

Our approach to this task has involved developing a comprehensive economic evaluation framework and applying it to compare the potential advantages and disadvantages of an inertia spot market against the long-term procurement approach under the ISF.

This report sets out insights resulting from our analysis. It is structured as follows:

- in section 2, we describe inertia services in the NEM, focusing on the need for inertia and how that need is being met through the ISF;
- in section 3, we examine the economics of inertia services and the opportunities to promote efficient investment in and provision of inertia services;
- in section 4, we evaluate alternative designs for inertia services, focusing on the minimum inertia requirements, operational top-up inertia services and additional inertia services; and
- in section 5, we present our methodologies and results of estimating economic benefits of operational top-up and additional inertia services.

[2] AEMC, *Improving security frameworks for the energy transition*, Rule determination, 28 March 2024.

[3] See AEMC website, available at: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia, accessed 26 November 2024.

In appendix A1, we describe our methodology for quantifying the economic benefits of operational top-up and additional inertia services, and in appendix A2 we summarise our inputs and assumptions. Appendix A3 sets out results of the sensitivity analysis for the economic benefits of additional inertia service.

2. Inertia services in the National Electricity Market

The National Electricity Market (NEM) is undergoing a significant transformation as traditional synchronous generation is progressively replaced by renewable energy sources, creating new challenges for maintaining power system security. Inertia, which has historically been provided as a natural byproduct of synchronous generation, plays a crucial role in maintaining frequency stability by resisting rapid changes in system frequency following disturbances.

In this section, we:

- examine the fundamental characteristics of inertia as a system service;
- describe the need for inertia including technical requirements for minimum levels of inertia;
- explore how declining synchronous generation is affecting inertia supply (from an investment perspective) across the NEM; and
- outline the new *Improving Security Frameworks* (ISF) rule change introduced in 2024 to help manage the procurement and availability of inertia through the energy transition.

We draw on this context in evaluating designs for an inertia service market in section 4.

2.1 What is inertia?

Inertia is a power system characteristic that refers to the immediate and inherent resistance to changes in system frequency provided by rotating masses that are electromagnetically coupled to the power system. Inertia plays a crucial role in maintaining frequency stability by slowing the rate of frequency change following contingency events or disturbances, providing vital time for frequency control services to respond and restore the balance between supply and demand.

The ISF rule change introduces the following definition of inertia into the National Electricity Rules (NER):[4]

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

Electricity grids must maintain stable frequency to operate safely and securely. The NEM operates at a frequency of 50Hz (or 'cycles' per second).[5] When contingency events create imbalances between demand and supply, they cause changes in frequency. The amount of inertia in the power system determines how quickly frequency changes following such disturbances, with more inertia resulting in a lower rate of change of frequency (RoCoF).[6] In this way, inertia provides a fundamental stabilising effect on the power system.[7]

In addition to its direct effect on RoCoF, we understand that inertia may affect power system stability in other ways, including by:[8]

[4] AEMC, *National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 No. 9*, p 44, definition of 'inertia'.

[5] See Origin Energy website, available at: https://www.originenergy.com.au/blog/what-is-fcas/, accessed 7 November 2024.

[6] AEMO, *Inertia in the NEM explained*, March 2023, p 1.

[7] AEMO, *Inertia in the NEM explained*, March 2023, p 2.

[8] Given that historically power system inertia has been abundant, the effects of different levels of inertia in the system are still being investigated. AEMO, *Inertia in the NEM explained*, March 2023, pp 2-4.

- stabilising the network following a disturbance through a geographically diverse distribution of inertia connected to the power system; and
- influencing other power system characteristics not directly related to frequency and RoCoF, such as by stabilising power system dynamics following a disturbance through a relationship with rotor angle stability.

Historically, inertia has been provided as a byproduct of synchronous generators including coal, gas and hydro plants. These plants use large spinning turbines and rotors that are electromagnetically coupled with the power system and synchronised to system frequency. These components are typically very heavy, weighing tens or hundreds of tonnes. The inertia they provide comes from the stored kinetic energy in their rotating masses. When synchronised to the grid, they inherently slow down changes in power system frequency immediately after an imbalance occurs.[9]

The total amount of synchronous inertia available to the power system at any time is based on the generation and load rotating mass connected to the power system.

Modern asynchronous generation technologies like wind turbines, solar inverters and batteries are connected to the power system through power electronic interfaces and do not automatically provide inertia. However, grid-forming inverter-based resources (IBRs) may also provide synthetic inertial responses,[10] provided they have sufficient headroom or foot-room, as discussed in section 3.2.3 below.

Inertia in a power system such as the NEM is measured in megawatt-seconds (MWs) or gigawatt-seconds (GWs). These units of measurement reflect the fact that inertia responds instantaneously and for a short amount of time following a disturbance.[11]

An inertia constant, measured in seconds, represents the amount of inertia that a generator provides per unit of its capacity while it is online.[12] For example, a generator with 100MW capacity and an inertia constant of 5 seconds provides 500MWs of inertia when it is online. The generator will provide the same level of inertia whenever it is operating at or above its minimum stable level – ie, the amount of inertia that a generator provides is independent of its actual output.

2.2 Minimum levels of inertia

We understand that minimum levels of inertia are required in the power system to:

- maintain frequency within acceptable bounds following credible contingency events. Without sufficient inertia, system frequency could change too rapidly for other frequency control services to respond effectively, potentially leading to system instability or collapse;
- ensure emergency control schemes like under-frequency load shedding remain effective. These schemes are designed to operate within specific timeframes following a disturbance. If frequency changes too rapidly due to insufficient inertia, these emergency schemes may not activate correctly or may not have time to arrest the frequency decline;
- provide sufficient time for frequency control systems to accurately measure and respond to disturbances. Frequency control systems require precise frequency measurements to respond appropriately. Very rapid frequency changes can make accurate measurement difficult, potentially leading to inappropriate or ineffective responses; and

[9] AEMO, *Inertia in the NEM explained*, March 2023, pp 1-2.

[10] This is subject to guidance from AEMO as to the technical requirements of synthetic inertia. See AEMO consultation page, available at: https://aemo.com.au/consultations/current-and-closed-consultations/amendments-to-the-inertia-requirements-methodology, accessed 26 November 2024.

[11] Denholm, P, Trieu, M, Kenyon, R W, Kroposki, B and O'Malley, M; *Inertia and the power grid: a guide without the spin*; National Renewable Energy Laboratory; May 2020, p 9.

[12] See Denholm, P, Trieu, M, Kenyon, R W, Kroposki, B and O'Malley, M; *Inertia and the power grid: a guide without the spin*; National Renewable Energy Laboratory; May 2020, p 11. The inertia constant of a synchronous generator depends on the mass and geometry of its turbine.

- meet required RoCoF limits. These limits are set to protect and maintain system stability.

A minimum level may apply to an entire power system and/or to particular regions within the power system that may be at risk of islanding (ie, temporary disconnection from the rest of the power system).[13] AEMO is responsible for calculating these minimum inertia requirements in the NEM, with the frameworks governing this process discussed in section 2.4 below.

The minimum inertia requirements depend primarily on two factors, namely:

- the desired RoCoF that the system can accommodate, which is specified in reliability standards and reflects both technical limitations of connected equipment and the speed of frequency control responses; and
- the largest credible contingency size, which determines the maximum potential initial frequency disturbance that the system must be able to manage.

Consequently, AEMO's minimum inertia requirements may change in response to:

- revisions to NEM reliability standards regarding acceptable RoCoF, which may evolve as technology capabilities change; or
- changes to the largest credible contingency size in the NEM or in any region at risk of islanding, which may be due to events including:
  - retirement of the current largest contingency (existing generator or load);
  - connection of new very large generators, such as an offshore wind farm, which becomes the largest contingency; and/or
  - renewable energy zones or other radial connections becoming a credible contingency.

While contingency size may also vary in operational timeframes, the minimum inertia requirements estimated by AEMO in its inertia report target planning/investment timeframes under existing frameworks – see section 2.4.

Importantly, above the minimum inertia requirements, inertia can be operationally substituted with other services like FFR to achieve similar power system stability outcomes – see section 4.4.1. This creates opportunities for more flexible and potentially more cost-effective approaches to maintaining frequency stability above the minimum levels.

AEMO has estimated minimum inertia requirements for the NEM, and each region within the NEM, from December 2024 to December 2034.[14] Figure 2.1 presents these minimum inertia requirements, based on the secure operating level for each region at risk of islanding,[15] and the allocation of mainland NEM minimum inertia requirements under interconnected operation for each region not at risk of islanding.[16]

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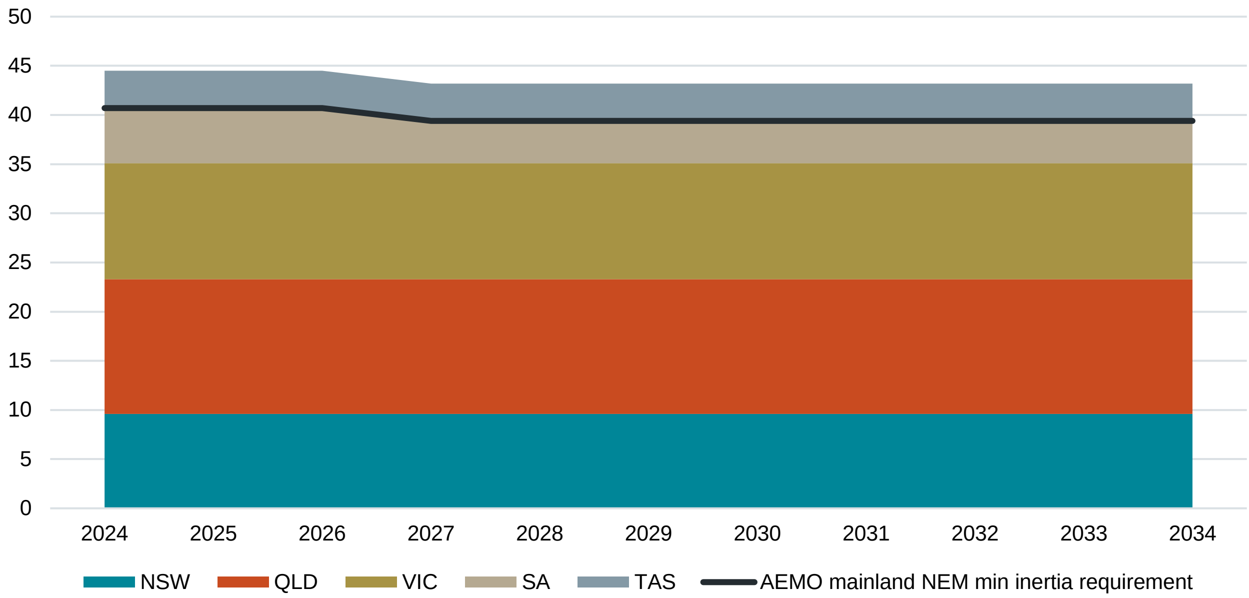
[13] See, eg, AEMC, *Improving security frameworks for the energy transition*, Rule determination, 28 March 2024, p 21.

[14] AEMO, *2024 Inertia report*, December 2024.

[15] Queensland and Tasmania are considered at risk of islanding. South Australia is considered at risk of islanding prior to the commissioning of stage 2 of Project Energy Connect (PEC), which is assumed to occur in 2027 (see AEMO, *2024 Inertia report*, December 2024, p 13). South Australia is considered not at risk of islanding after the commissioning of PEC.

[16] See AEMO, *2024 Inertia report*, December 2024, p 3.

Figure 2.1: Minimum inertia requirement based on AEMO's 2024 inertia report (GWs)



The black line represents the minimum inertia requirement for the mainland NEM projected by AEMO through to 2034. The black line sits at 39.4 GWs following the commissioning of Project Energy Connect (PEC), which the chart above assumes will occur in 2027. AEMO's minimum inertia requirement for the mainland NEM is 40.7 GWs before the commissioning of PEC.

2.3 Declining inertia in the NEM as synchronous generation capacity reduces

As coal and gas plants retire from the NEM, the provision of synchronous inertia as a byproduct of synchronous generation will decline significantly, absent any intervention. However, this decrease corresponds with a period of expected investments to meet system strength obligations, primarily by TNSPs, which can be adapted to also provide inertia at a low incremental fixed cost. System strength investments may include:[17]

- synchronous condensers;
- contracting with grid forming battery energy storage systems (BESS);
- contracting with synchronous generators; and/or
- other technologies such as clutched gas turbines.

Many of these technologies can also provide inertia at relatively low incremental fixed cost, and so may be used to at least partially offset the declining inertia in the NEM as synchronous generation capacity reduces. We discuss sources of inertia in more detail in section 3.2.

To understand the potential need for investment in capacity to provide inertia into the future we have considered how much inertia is expected to leave the system as existing synchronous generation retires, as well as how much potential inertia capacity might be expected to come online as TNSPs invest in technologies to meet system strength obligations.

[17] See Powerlink, *Assessing system strength requirements in Queensland from December 2025*, PADR, November 2024, pp 17-20; and Transgrid, *Meeting system strength requirements in NSW*, PADR, June 2024, p 2.

For this analysis, we have focused on synchronous condenser investment forecasts for system strength purposes, assuming that a 1000 MWs flywheel is added to any newly built synchronous condenser. This assumption is in line with expectations set out in recent system strength project assessment draft reports (PADRs) by Transgrid and Powerlink, and the AER's recent guidance on the efficient management of system strength in the NEM.[18]

Figure 2.2 presents projected mainland NEM inertia capacity in three scenarios:

- existing synchronous generators only (no synchronous condensers);
- existing synchronous generators plus synchronous condensers expected in the next eight to ten years based on current TNSP RIT-T documents (high scenario);[19] and
- existing synchronous generators plus a conservative subset of synchronous condensers expected based on TNSP RIT-T documents (low scenario).

Existing synchronous generator capacity is based on the nameplate capacity and expected retirement dates for each existing synchronous generator from AEMO's October 2024 generation information page,[20] and an inertia constant for each generator sourced from AEMO's Electricity Data Model.

The high scenario includes synchronous condensers required to meet minimum fault level requirements over the next eight to ten years under a PADR preferred option (New South Wales and Queensland),[21] a project specification consultation report (PSCR) indicative network investment plan (South Australia and Victoria),[22] or expected to be built in the Central-West Orana REZ.[23] The low scenario includes a subset of these investments – for example, in New South Wales and Queensland, the minimum number of synchronous condensers included under any of the credible options considered by Transgrid or Powerlink in their respective PADRs. More detail on each scenario is provided in appendix A2.25.4.2A2.2.

Figure 2.2 includes the AEMO mainland NEM minimum inertia requirement discussed in section 2.2 as a comparison. The actual minimum or secure level in the future is uncertain, particularly beyond 2034, as discussed in section 2.2.

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[18] Powerlink, *Assessing system strength requirements in Queensland from December 2025*, PADR, November 2024, p 58; Transgrid, *Meeting system strength requirements in NSW*, PADR, June 2024, p 30; and AER, *The efficient management of system strength framework*, AER draft guidance, October 2024, p 31.

[19] We note that the high scenario does not include all synchronous condensers that may be expected based on TNSP RIT-T documents, and so should not be treated as an upper bound. Appendix A2.2 sets out which synchronous condensers are included in each scenario.

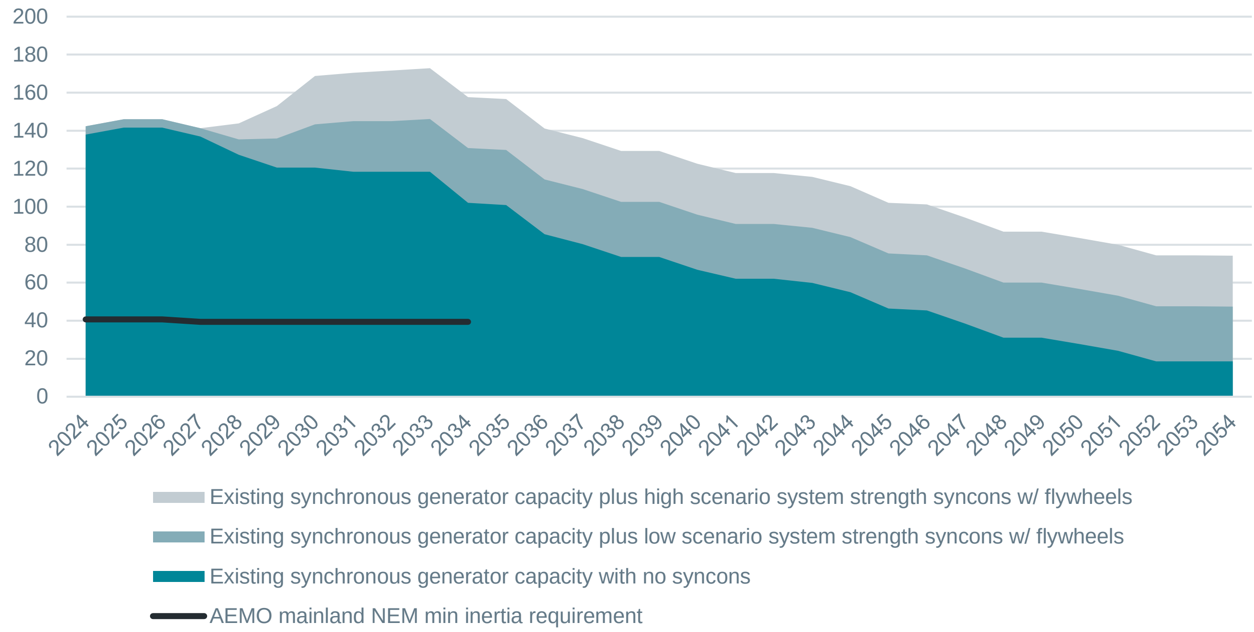
[20] See AEMO website, available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information, accessed 7 November 2024.

[21] Powerlink, *Assessing system strength requirements in Queensland from December 2025*, PADR, November 2024, pp 17-20; and Transgrid, *Meeting system strength requirements in NSW*, PADR, June 2024, p 30..

[22] AEMO Victorian Planning, *Victorian System Strength Requirement*, PSCR, July 2023, pp 17-19; and ElectraNet, *System Strength Requirements in SA*, PSCR, November 2023, pp 11, 21.

[23] See Transgrid, *Meeting system strength requirements in NSW*, PADR, June 2024, p 30; and AEMO, *NEM transmission augmentation information August 2024*, 'Transmission augmentations' sheet, row 16.

Figure 2.2: Projected mainland NEM inertia capacity (GWs)



It is important to note that not all this capacity will be available at any given time. For example, synchronous generators will experience planned and unplanned outages.

Figure 2.3 and figure 2.4 consider the inertia from synchronous generators that may be online on average at the same time. To provide an indication of average synchronous generator inertia relative to capacity, a capacity factor has been applied to each generator, based on fuel type.[24] This approach does not capture the fact that generators may operate below their maximum capacity and still provide inertia, and so the actual available/online inertia from synchronous generation may be higher on average than what is shown here.

In this analysis, we assume that synchronous condensers with flywheels, if they are to be built, could be available at any time. Figure 2.3 includes inertia from synchronous condensers with flywheels built in the high scenario described above, while figure 2.4 includes those built in the low scenario.

[24] Capacity factors of 0.62 for black coal generators, 0.78 for brown coal, 0.14 for gas, and 0.25 for hydro have been applied. These capacity factors are based on the ratio of generation output to generation capacity from each fuel type - see: AER, *Data – state of the energy market 2023 – Chapter 3 – National Electricity Market*, 'Figure 3.14' and 'Figure 3.15' sheet. Owing to the higher capacity factor of coal generators relative to gas and hydro, the average capacity factor applied across all synchronous generators gradually falls as coal generators retire, from approximately 40 per cent in 2024 to 20 per cent in 2054.

Figure 2.3: Existing generator average inertia plus system strength synchronous condensers with flywheels (high scenario) (GWs)

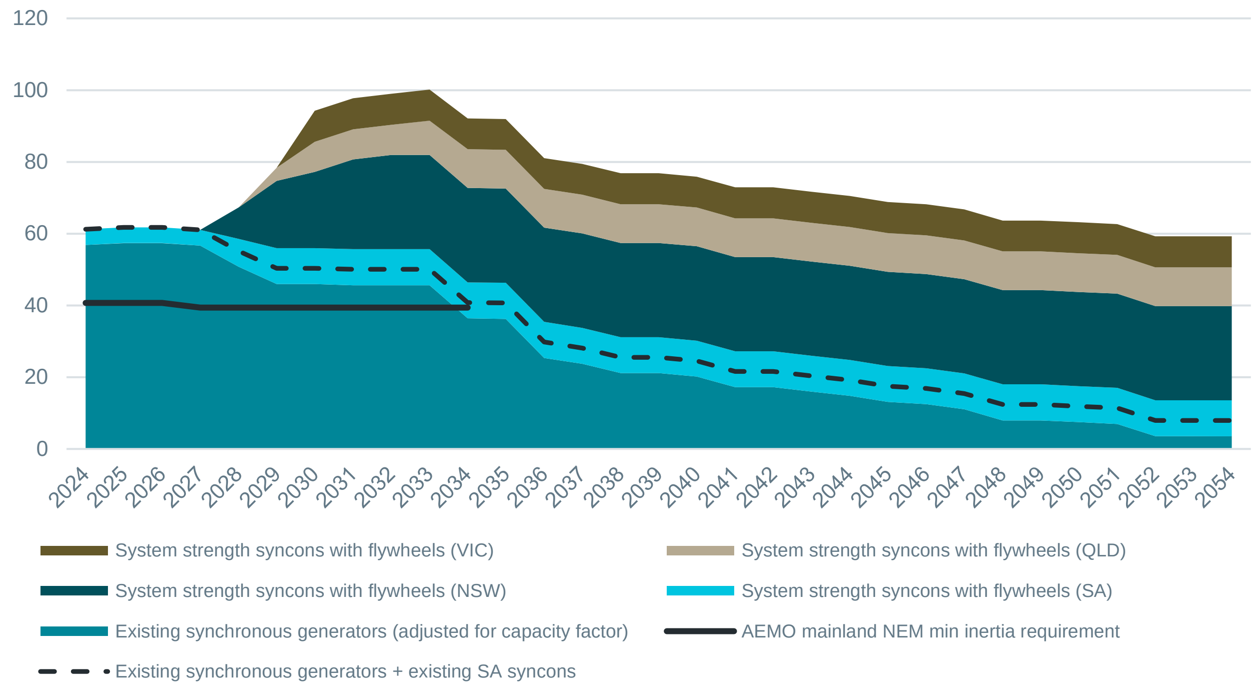
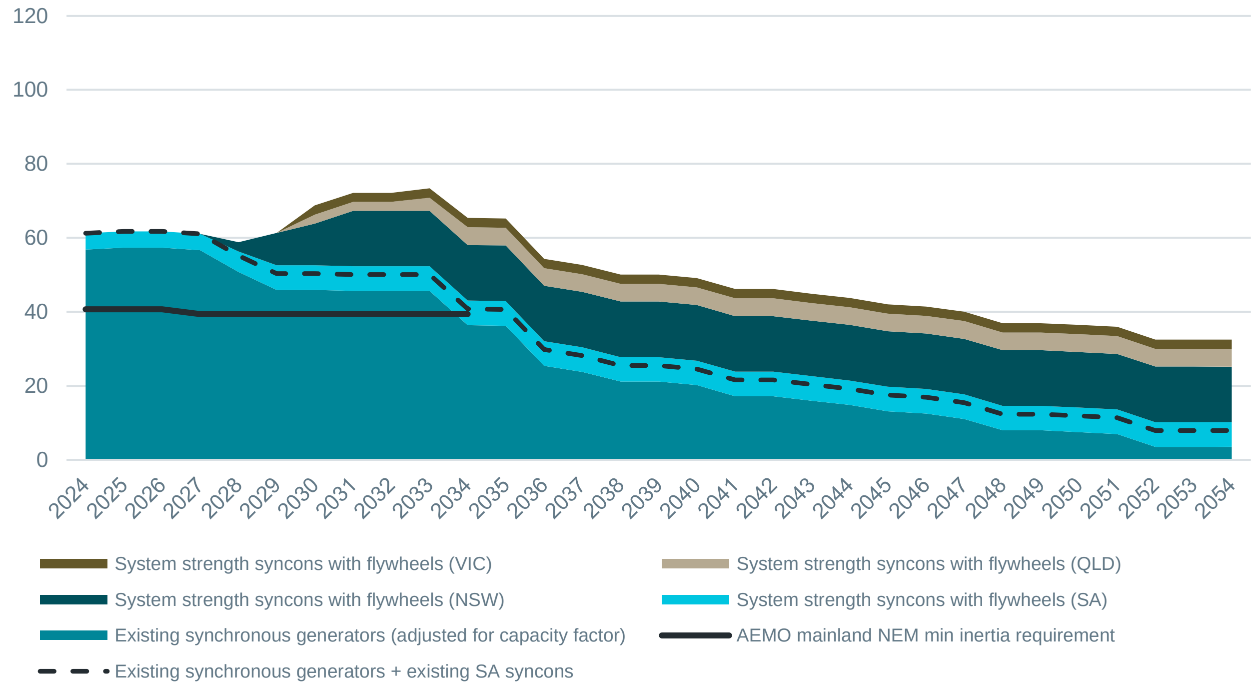


Figure 2.4: Existing generator average inertia plus system strength synchronous condensers with flywheels (low scenario) (GWs)



The analysis is consistent with a conclusion that system inertia capacity in the NEM is unlikely to fall below minimum requirements in the short to medium term, given anticipated investment in synchronous condensers (with flywheels) or alternative system strength technologies that may also be adapted to provide inertia.

That said, this analysis does not capture fluctuations in synchronous generator availability between dispatch intervals in operational timeframes, or between different regions in the NEM, which could result in some periods of low inertia, thereby requiring other operational interventions to maintain system security.

Without any investment in synchronous condensers, other technologies would likely be required to provide inertia by the late 2020s (noting that four 1,100MWs synchronous condensers in South Australia have already been built – see the dotted line in the charts above).

While our analysis has focused on synchronous condensers as the technology used to meet system strength obligations, with flywheels added to provide inertia at low incremental cost, our conclusions about future inertia capacity are not dependent on this specific technology choice.

TNSPs may choose to meet their system strength obligations through alternative technologies, such as grid-forming batteries or other emerging solutions. These alternatives could also provide inertia services, either through synthetic inertia capabilities or by enabling integration of other inertia sources. Whatever technology mix ultimately emerges, the key insight is that system strength investments – which TNSPs are required to make – create an opportunity to efficiently provide inertia services through incremental investment in inertia capabilities. For example, while synchronous condensers can be fitted with flywheels, grid-forming batteries could potentially provide both system strength and synthetic inertia through appropriate inverter controls and settings.[25]

2.4 2024 improving security frameworks for the energy transition rule change

AEMO, since before the ISF rule change, is responsible for determining two key inertia requirements for each sub-network (region) in the NEM, ie:[26]

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

AEMO assesses potential inertia shortfalls by comparing requirements against the typical levels of inertia available through normal dispatch patterns. Where AEMO identifies a shortfall, the relevant TNSP must address it by making the minimum required inertia continuously available.

The March 2024 ISF rule change, which commenced on 1 December 2024, expanded this framework by:[27]

- introducing a mainland inertia floor to be set by AEMO, which is to be allocated across regions on a proportional basis taking account of regional inertia needs (see section 2.2, above);
- continuing to require AEMO to forecast secure levels for regions at risk of islanding;
- requiring AEMO to forecast inertia needs over a ten year period;
- requiring TNSPs to procure inertia to meet the floor (or the secure level where there is a risk of islanding) three years in advance;

[25] The analysis above relates solely to upfront investment in technologies that could provide inertia. We discuss in section 3 that different technologies will have different cost functions and technical requirements to provide inertia.

[26] See AEMO, *2023 inertia report*, December 2023, p 7.

[27] AEMC, *Improving security frameworks for the energy transition*, Rule determination, 28 March 2024, pp 18-19.

- allowing synthetic inertia to be considered as a source of inertia and requiring AEMO to publish detailed specification of the technical requirements for providers of synchronous and synthetic inertia; and
- allowing short-term procurement of inertia through the network support and control ancillary services (NSCAS) framework where near-term gaps (within the three-year procurement window) arise.

Both the existing framework and the amended ISF framework rely on TNSPs procuring inertia services through ahead-of-time contracts. The key difference is that the new framework provides more comprehensive planning requirements and greater flexibility in how inertia can be provided.

3. Promoting efficient delivery of inertia services

The delivery of inertia services in the NEM involves complex interactions between system security requirements, technological capabilities, and economic trade-offs. As the power system transitions away from traditional synchronous generation and new sources of inertia services are needed, there are opportunities to promote more efficient delivery of these essential services through improved market and regulatory frameworks.

In this section, we examine how different market designs could better support both efficient investment in inertia-providing technologies and their optimal deployment in operational timeframes. We consider the technical and economic characteristics of different inertia sources, the relationship between inertia and other frequency control services like FFR, and how market design choices can impact investment signals and operational efficiency. Understanding these factors is critical for evaluating potential reforms to move beyond the current contract-based procurement approaches.

3.1 Defining inertia services for evaluation

In this section, we set out the terminology that has been used throughout this report. We consider this is crucial to bring clarity to the different types of inertia services assessed in our analyses.

An inertia service can be defined as any activity that provides inertia to the power system for the purpose of:

- meeting minimum levels required to maintain secure operation, particularly during islanded conditions (***minimum inertia***); or
- delivering market benefits by providing inertia services above the level provided through energy dispatch, where this exceeds operational minimum levels (***additional inertia***).

The minimum inertia needs differ between planning and operational timeframes. **Minimum inertia requirements** refer to the minimum levels required by AEMO in planning timeframes, as described in sections 2.2 and 2.4 above.

At an operational timeframe, minimum inertia needs may not be met due to unavailable capacity. In these instances, there is an operational inertia shortfall (ie, the amount of inertia available through energy dispatch is lower than the operational minimum inertia need). To address inertia shortfalls in operational timeframes, AEMO can either:

- decrease the contingency size of the system; or
- direct synchronous generators to synchronise or remain synchronised.

Operational top-up inertia refers to inertia services that supplement the inertia naturally available through energy dispatch when needed to meet minimum inertia needs. It follows that operational top-up inertia services could avoid the need for AEMO to address inertia shortfalls through changes to contingency size or directions.

Our economic evaluation of market designs for inertia services considers three types of inertia services, ie, minimum inertia requirements, operational top-up inertia, and additional inertia. A summary of the definition of these inertia services, for the purpose of our economic assessment, is set out below.

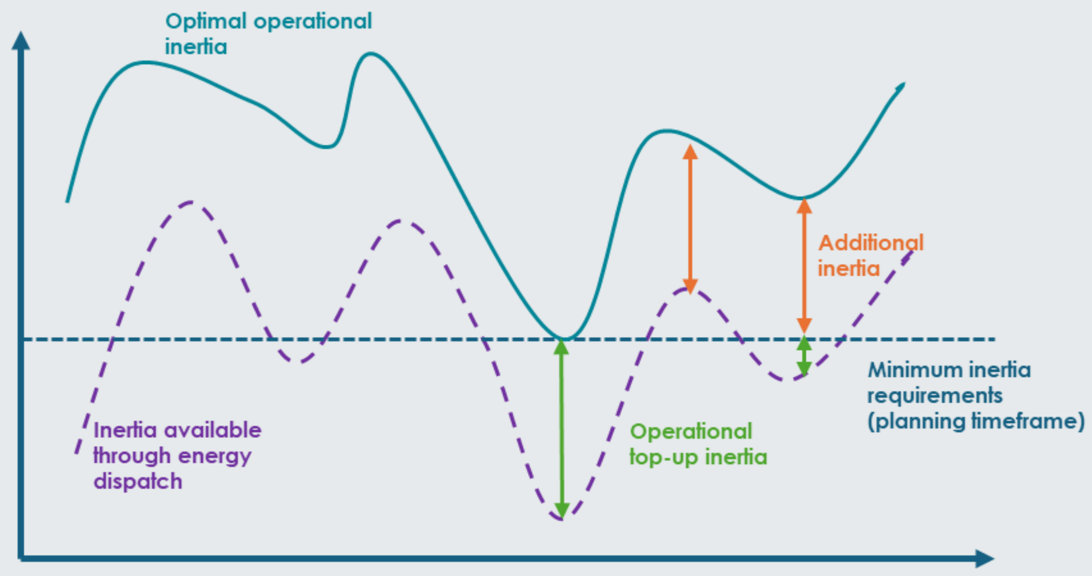
Box 3.1: Definition of inertia services for evaluation in this report

Minimum inertia requirements refer to the minimum planning levels of inertia required to maintain secure operation of the power system.

Operational top-up inertia refers to the provision of inertia that addresses inertia shortfalls with respect to the minimum inertia needs that arise in operational timeframes.

Additional inertia refers to the provision of inertia above operational minimum needs and above the level provided through energy dispatch, when this delivers economic benefits.

An illustrative diagram for these inertia services is presented below.



For the purpose of the economic evaluation, the three types of inertia services defined above are grouped into two distinct categories based on the opportunities for achieving operational efficiencies through market mechanisms, ie:

- the first category consists of minimum inertia requirements; and
- the second category consists of operational top-up inertia and additional inertia.

The first category focuses on mechanisms for meeting minimum inertia requirements at a planning level. This involves ensuring that there is sufficient inertia capacity to maintain power system security, particularly during islanded conditions. Under the ISF, this is achieved through long-term procurement by TNSPs. Our evaluation considers whether alternative market designs could deliver this essential system security service more efficiently while maintaining the high degree of certainty required for system security.

The second category examines market designs for delivering inertia services that can provide market benefits. This encompasses operational top-up inertia that is otherwise provided by reducing contingency size or directions in operational timeframes, and additional inertia above the level provided through energy dispatch, where this exceeds operational minimum levels.

By evaluating market designs separately for these two categories, we can better account for their different characteristics – particularly around substitutability, value, and the certainty required in their provision – while ensuring our assessment framework appropriately captures the costs and benefits specific to each role.

3.2 Sources of inertia

The power system relies on several key technologies to provide inertia services, each with distinct operating characteristics and capabilities. These sources can be broadly categorised into synchronous generators and newer technologies that can provide similar frequency response characteristics.[28]

3.2.1 Synchronous generators

Synchronous generators have historically been the primary source of inertia in the power system, providing this service as a natural byproduct of electricity generation. Section 2.1 explains that these units, which include coal, gas, and hydro generators, operate with large spinning turbines and rotors that are synchronised to the grid frequency. Their rotating masses, typically weighing tens or hundreds of tonnes, provide mechanical inertia that inherently helps resist changes in system frequency following disturbances.

Key characteristics of synchronous generators providing inertia include:

- inertia provision has a binary production function - either maximum or no inertia is provided – because the same level of inertia is provided whenever the generator is online and operating above its minimum stable level;
- they must operate at least at minimum generation levels to provide inertia;
- they can simultaneously provide other essential system services like system strength;
- inertia levels are fixed based on physical characteristics of the machine; and
- operation and availability are driven primarily by energy market outcomes rather than inertia needs.

While synchronous generators remain important providers of inertia, their role is diminishing as the power system transitions toward renewable generation.[29] This changing operational environment has seen traditional synchronous plants running less frequently or retiring altogether, reducing the "always on" inertia that the system historically relied upon. This transition is driving the need to establish explicit mechanisms for valuing and procuring inertia services that were previously available in abundance.

3.2.2 Synchronous condensers

Synchronous condensers with flywheels provide a dedicated source of inertia without generating energy, operating as freely spinning machines synchronised to the grid frequency. These devices can be purpose-built for inertia and system strength services or created by converting retired generators to operate in synchronous condenser mode.[30]

A key advantage of newly built synchronous condensers is their ability to be equipped with additional flywheels during construction, which can substantially increase their inertia contribution at relatively low incremental cost.[31]

Other key characteristics of synchronous condensers include:

- can provide inertia without needing to generate energy;

[28] We understand that synchronous load can also provide inertia. That said, given uncertainty about the discretionary availability of this source inertia, we have not expressly considered synchronous load as a source of inertia for the purposes of our evaluation.

[29] We note that hydro generators are expected to play an important role in the future energy mix. However, synchronous generation is still expected to decrease in aggregate as coal and gas power plants retire.

[30] See Digsilent, *Repurposing existing generators as synchronous condensers*, Report on technical requirements for ARENA, June 2023. Also see Appendix A2.1 regarding inertia from repurposing a synchronous generator to operate as a synchronous condenser for further detail. Some existing hydro generators can also operate in synchronous condenser mode.

[31] Retrofitting a flywheel to an existing synchronous condenser, or to a generator which is being repurposed as a synchronous condenser, is more expensive than adding a flywheel during construction of a new synchronous condenser. See AEMO, *2023 Inertia report*, December 2023, p 4, footnote 2.

- draw small amounts of power from the grid to overcome friction losses;
- can be strategically located where inertia is needed;
- currently being considered as a core part of near-term system strength solutions by TNSPs; and
- can provide both inertia and system strength services simultaneously.

Synchronous condensers are likely, based on current TNSP expectations, to play an important role in maintaining power system security as traditional synchronous generation declines. TNSPs are currently planning to deploy these assets as part of system strength solutions,[32] creating opportunities to optimise investment by adding inertia capability through flywheels.

3.2.3 Inverter based technologies

Modern inverter-based resources (IBRs) can provide synthetic inertial response through advanced grid-forming controls, offering an alternative to traditional synchronous inertia. Unlike synchronous machines where inertia is a fixed physical characteristic, grid-forming inverters can be designed to provide variable levels of inertial response up to their technical limits. This capability is becoming increasingly important as the power system transitions away from synchronous generation, though there is not yet sufficient real-world experience of synthetic inertial responses being deployed at scale to fully rely on synthetic inertia or assess its system-wide interactions.[33]

Key characteristics of grid-forming inverter responses include:

- must maintain sufficient headroom/foot-room in capacity to provide inertial response;
- can provide inertia while charging, discharging, or idle;
- can be tuned to provide different response profiles;
- often able to provide other frequency control services like FFR; and
- is being considered as part of system strength solutions by TNSPs.[34]

While synthetic inertia could theoretically replace synchronous inertia for frequency management purposes, we understand that current power system understanding, and operational experience suggests maintaining some minimum level of synchronous inertia in the near term. Grid-forming capabilities are still evolving, with ongoing improvements in measurement techniques, control systems, and operational experience gradually expanding their role in maintaining system security. The provision of synthetic inertia through batteries can be particularly valuable as it allows the potential to co-optimise with energy storage and other frequency control services.

3.2.4 Implications for choice of market design

The diverse characteristics of inertia-providing technologies have important implications for designing market designs for inertia services. The optimal mix of these technologies for providing inertia services depends on their relative costs, technical capabilities, and ability to provide other system services. For instance, synchronous condensers can provide both inertia and system strength, while grid-forming batteries can provide inertia alongside energy arbitrage, system strength and frequency control services, subject to the characteristics outlined in section 3.2.3 above.

[32] See section 2.3.

[33] See, eg, AEMO, *Inertia in the NEM explained*, March 2023, pp 3-4.

[34] The extent to which IBR can contribute towards the minimum level of system strength is bring further investigated by TNSPs. See, eg, Powerlink, *Assessing system strength requirements in Queensland from December 2025*, PADR, November 2024, pp 23-24.

The different characteristics across inertia technologies and the complex interactions with other system services create challenges and opportunities for promoting the efficient delivery of inertia services in the NEM. We expand on these challenges and opportunities in section 4.

3.3 Costs of providing inertia from different sources

Understanding the costs of providing inertia from different sources is essential for evaluating market design options and promoting efficient investment and operational decisions. The cost structures vary significantly across technologies and operating modes - from synchronous generators that must cover energy operating costs to provide inertia, to synchronous condensers with high fixed but low operating costs, to grid-forming batteries where costs relate primarily to maintaining headroom and foregoing revenue opportunities in energy and FCAS markets.[35]

These varying cost structures, combined with differences in technical capabilities and ability to provide other system services, create both challenges and opportunities for market design. By understanding these cost characteristics, we can better evaluate how different market designs might promote efficient technology choices while enabling operational trade-offs that minimise overall system costs.

Table 3.1 provides a high-level summary of our estimates of the incremental cost of providing inertia services from different sources. We have included an estimated emissions cost, to emphasise that there are different implications for emissions across the sources, even though these are not directly financial costs of providing inertia. In appendix A2.1, we provide more detailed information on the incremental costs of inertia by source and set out how these estimates have been calculated.

Table 3.1: Summary of incremental costs to provide inertia services by source

Inertia source		Fixed cost ($/MWs/year)	Variable cost ($/MWs/hour)	Emissions cost ($/MWs/hour)
Traditional synchronised generation				
Existing synchronised generation		$0	$0	$0
Earlier or prolonged dispatch of existing synchronised generation		$0	$0.30-$1.10	$1-$9
Delay shutdown of existing synchronised generation **(current, expected to increase)**		$700 - $9,000	$0.30-$1.10	$1-$9
Synchronous condensers				
Add flywheel to system strength syncon during construction		$170	Very low incremental	Very low
Retrofit flywheel to existing syncon (new or repurposed generator)		Uncertain, significantly higher than $170	Very low incremental	Very low
Build syncon for inertia, with a flywheel	New	$7,600	$0.20-$0.50	low
	Repurposed	$1,900 - $4,900		low

[35] We understand that there may also be some trade-offs associated with the provision of system strength and inertia, but that in many cases a BESS is likely to be able to make a significant contribution to inertia without sacrificing its ability to provide system strength.

Inertia source		Fixed cost ($/MWs/year)	Variable cost ($/MWs/hour)	Emissions cost ($/MWs/hour)
			(assuming electricity consumption equal to 1.5% of syncon rating)	
Synthetic inertia				
Synthetic inertia from IBRs	1hr, 2024	$0-$806	$0.44 (*estimated*)	$0
	1hr, 2030	$0-$488	$0.44 (*estimated*)	$0

The incremental costs of providing inertia set out in the table above do not include costs that would be incurred regardless to provide other services (eg, energy, system strength).

3.4 Promoting efficient investment in inertia technologies

Promoting efficient investment in inertia-providing technologies is critical as the power system transitions away from traditional synchronous generation. Investment efficiency has two key dimensions:

- ensuring that the lowest-cost combination of technologies is constructed to meet system needs, and
- creating an environment that encourages innovation and competition to reduce costs over time.

The efficient mix of inertia technologies depends on both their cost characteristics and technical capabilities:

- synchronous condensers have high upfront capital costs but very low operating costs;
- adding flywheels during initial construction is substantially cheaper than retrofitting;
- grid-forming inverter capabilities can be added to batteries that provide multiple services;
- some technologies can provide both inertia and other system services like system strength; and
- different technologies may be more efficient in different locations or operating conditions.

To promote efficient investment outcomes, market and regulatory frameworks need to balance multiple objectives. Long-term procurement mechanisms can provide investment certainty for capital-intensive technologies, while spot market arrangements can reveal the operational value of inertia services. Together, these create incentives for investors to select the most cost-effective technologies for different applications.

Dynamic efficiency is particularly important given the rapid evolution of grid-forming inverter capabilities. Market designs should encourage continued innovation in both conventional and emerging technologies. This includes creating opportunities for new technical solutions to compete with established approaches, while ensuring system security requirements are maintained. Over time, competitive pressures and technological advancement should drive down the cost of providing inertia services across all timeframes.

The key challenge is designing frameworks that achieve both productive and allocative efficiency (selecting the lowest cost technology mix today to provide a range of system security and energy services) and dynamic efficiency (promoting innovation and cost reduction over time).[36] This suggests value in implementing complementary mechanisms that address different aspects of investment efficiency while maintaining strong incentives for technological development.

[36] We discuss different types of efficiency in more detail in section 4.1.1, below.

3.5 Promoting efficient operational availability of inertia services

The efficient availability of inertia services in operational timeframes requires careful consideration of different technologies' cost structures and operational characteristics. The optimal mix of inertia providers potentially can vary based on the level of inertia needed, system conditions, and interaction with other frequency control services. This creates potential opportunities to reduce overall system costs through more dynamic approaches to procuring and dispatching inertia services.

Cost structures for providing inertia vary significantly across technologies and operating conditions:

- some units have low fixed costs but high variable costs (such as requiring some synchronous generators to remain online);
- others have high fixed costs but low variable costs (like synchronous condensers);
- grid-forming batteries may have different costs depending on lost opportunities in energy and FCAS markets; and
- costs can vary with the duration of service provision and notice period required.

This diversity in cost structures creates potential opportunities for operational efficiency:

- using low-variable cost providers for baseline inertia needs;
- dispatching higher-variable cost providers only during peak inertial requirements;
- co-optimising inertia provision with FFR requirements; and
- considering trade-offs between inertia levels and manageable contingency sizes.

The opportunity to promote efficient operational availability of inertia services directly relates to the economic concept of allocative efficiency - where resources are allocated to their most productive or highly-valued uses in the economy.

In the context of inertia services, allocative efficiency is achieved when the optimal mix of technologies are deployed to provide inertia services in operational timeframes. This means that at any point in time, the required level of inertia is provided by those participants who can do so at lowest cost.

4. Evaluating designs for an inertia service market

In this section, we evaluate from first principles alternative market designs that could efficiently facilitate the provision of inertia services in the NEM.

4.1 Economic framework for evaluating inertia market designs

Our evaluation of potential market designs for inertia services begins with a first principles economic analysis of how different market arrangements can facilitate efficient provision of inertia services. This foundational approach allows us to systematically assess how the underlying characteristics of inertia services - including their technical requirements, cost structures, and competitive dynamics – should inform the choice of market design.

4.1.1 Considerations for designing a market

In developing our framework, we begin by recognising that a market, at its most basic level, is a collection of buyers and sellers who, through their actual and potential interactions, determine the price of a product.

It follows that the concept of a 'market' is a broad term in economics that can encompass many different structural arrangements. These various market designs have evolved to facilitate efficient trade under different circumstances. Common examples include (amongst others):

- real-time spot markets – typically used for buying and selling commodities such as wheat and electricity, where prices adjust frequently to reflect changing supply and demand conditions;
- long-term contracting arrangements – used to provide revenue and cost certainty over extended periods, as seen in long-term gas supply contracts or maintenance service agreements;
- auction markets – employed when the prevailing price or value is uncertain and needs to be discovered through a competitive bidding process, such as in housing markets or fish markets; and
- forward markets – used to manage future price risk and coordinate production and consumption decisions ahead of time.

When evaluating which market design might best facilitate efficient outcomes for inertia services, we need to carefully consider the characteristics that reflect both the nature of the product or service being traded and how it is produced or supplied. These characteristics help determine which market design is likely to be most effective at promoting economically efficient outcomes.

Promoting efficient outcomes has three dimensions, namely when:

- resources are allocated to their most productive or highly-valued uses in the economy. This is achieved by ensuring that prices of goods or services reflect the underlying marginal costs of supply, which supports efficient investment and expansion in productive capacity over time – economists refer to this as allocative efficiency;
- a product or service is produced at the lowest possible cost – economists refer to this as productive efficiency; and
- there is efficient allocation and production of goods and services over time, which requires engaging in activities to pursue better products and ways of producing goods or services through innovation – economists refer to this as dynamic efficiency.

Considering all three dimensions of economic efficiency is crucial when evaluating alternative market designs, as different market designs may promote some dimensions of efficiency while potentially compromising others.

For example, long-term contracting might effectively promote productive efficiency by providing investment certainty that enables lowest-cost technology choices but can weaken incentives for dynamic efficiency if contract periods are too long or specifications too rigid to allow new technologies to compete.

Similarly, while a spot market might achieve strong allocative efficiency by enabling real-time optimisation between different providers and substitutable services, it may create investment uncertainty that compromises productive efficiency. This might be a greater concern if the economic consequences of under supply are significant.

The optimal market design therefore needs to carefully balance these different dimensions of efficiency, recognising the interactions and any potential trade-offs between them. This is particularly important for inertia services, where we need to simultaneously encourage efficient investment in new technologies, optimal deployment of existing resources, and continued innovation in service provision over time.

4.1.2 Evaluating alternative market designs for inertia services

To develop a robust framework for evaluating alternative market designs for inertia services, we have undertaken a comprehensive analysis of both the demand and supply characteristics that shape these services. This evaluation recognises that different market designs may be more or less effective depending on the underlying economic and technical characteristics of the service being provided.

Our assessment framework considers five key characteristics that influence the efficiency and effectiveness of different market designs:

- the nature of the inertia service itself – specifically whether it can be clearly defined and the extent to which service requirements may need to evolve over time;
- opportunities for efficiency gains, including through technological innovation and optimal combinations of different supply technologies across both operational and planning timeframes;
- the economic consequences of under or over supplying inertia services, particularly given inertia's essential role in maintaining power system security;
- the need for investment certainty to incentivise development of inertia-providing technologies; and
- the likely extent of competition in supplying inertia services, including whether there are sufficient potential providers to support a competitive market.

Importantly, these characteristics and their implications for market design differ significantly between minimum inertia requirements and other inertia services (ie, additional inertia and operational top-up inertia). Minimum inertia requirements need absolute certainty of supply to maintain system security, while operational top-up and additional inertia allows for more flexible provision based on economic trade-offs given alternative mechanisms for managing power system operations to maintain security of supply.

Our analysis suggests that the economic costs of under or over supply vary markedly between these two types of inertia services. This variation has important implications for the choice of market design, as different mechanisms may be better suited to managing these distinct risk profiles.

We have synthesised these considerations into a comprehensive evaluation framework, summarised in table 4.1, which maps how different service characteristics influence the theoretical preference for alternative market designs. This framework provides a systematic basis for assessing which market design elements are likely to be most effective for different categories of inertia services.

The framework we have developed recognises that no single market design is likely to be optimal across all circumstances. Rather, the preferred approach depends on the specific characteristics of the service being procured and the context in which it will be delivered.

Table 4.1: Characteristics to consider when evaluating market design choices

Characteristics	If the product / service has the following characteristics:	
Product / service characteristics	Product / service can be well defined	Product / service may need to vary over time
Mechanism to manage financial investment risks for product / service with significant upfront investment needed, or time required, to supply the market	There are greater opportunities to use secondary markets to manage financial investment risks of a significant upfront investment	There are limited opportunities to use secondary markets to manage financial investment risks
Opportunity for least-cost technology mix for supplying product / service over time – allocative efficiency	There is a greater opportunity for product / service to be supplied through a least-cost mix of technologies over time	There is less opportunity for product / service to be supplied through a least-cost mix of technologies over time
Opportunity for supplying product / service at the lowest possible cost – productive efficiency	There is scope for ongoing competition to drive costs down over time	There is less scope for ongoing competition to drive costs down over time
Opportunity for future innovation on the supply side – dynamic efficiency	There is potential for future innovation to lower costs over time	There is less likelihood for future innovation to lower costs over time
Economic cost of under supply	The economic cost of under supply is likely low given consequences to the market	The economic cost of under supply is likely high given consequences to the market
Economic cost of over supply	The economic cost of over supply is high	The economic cost of over supply is low
Market liquidity	Competition between suppliers is effective and so the market is liquid	Competition between suppliers is more limited and so there may be market power concerns
	… then a spot market is likely to be preferred	**… then a long-term procurement mechanism is likely to be preferred**

4.1.3 Examining the two potential markets for inertia services separately

The analysis of inertia services markets necessitates a bifurcated approach, namely:

- **minimum inertia requirements** – these services fulfill the critical requirement of maintaining a minimum threshold level of inertia for secure system operation within a planning horizon, with particular emphasis on managing islanded conditions. This market addresses essential system security needs that must be met; and
- **operational top-up and additional inertia services** – these encompass operational situations where providing inertia above the operational level determined through dispatch can generate positive market benefits, or to satisfy operational minimum power system needs. This market segment responds to economic benefit opportunities.

This acknowledges the fundamental differences in both the nature of these services and their economic characteristics.

The rationale for this separated analysis stems from the distinct economic cost structures associated with each service type. Minimum inertia services, being essential for system security, may warrant a different market design compared to operational top-up and additional inertia services, which can be more readily subjected to traditional market forces within a spot market. This fundamental difference in economic characteristics suggests that applying a single market design to both services could result in suboptimal outcomes, making a differentiated approach more appropriate for market design and implementation.

4.2 Defining market designs for evaluation

For our assessment of potential inertia service market designs, we have focused on evaluating two principal alternatives: a real-time spot market mechanism and a long-term contract market approach. While other market designs exist for procuring various goods and services, the unique characteristics of inertia services – particularly the need for continuous availability and the relatively limited number of potential suppliers – make many alternative procurement approaches likely impractical.

The spot market approach would function similarly to the existing NEM energy spot market. Under this design:

- suppliers would submit price-quantity bids to provide inertia capacity (measured in MWs) for each dispatch interval;
- AEMO would determine the required quantity of inertia based on system conditions;
- the market clearing engine would dispatch the least-cost combination of inertia capacity to meet the requirement; and
- all dispatched inertia capacity would receive the market clearing price.

In contrast, the long-term contract market would operate through competitive tender processes where:

- AEMO would specify upfront the required inertia capacity and availability requirements;
- the procuring body (eg, TNSPs) would be required to procure sufficient inertia capacity to satisfy AEMO's requirements;[37]
- suppliers would compete through tender submissions specifying their offered capacity and price;
- successful tenderers would be paid their bid price for making the contracted capacity available; and
- contract durations would likely be multiple years to support investment certainty.

We have not pursued evaluation of other potential market designs, such as day-ahead markets or frequent auction processes, as these are unlikely to be well-suited to inertia services. This reflects both the need to ensure inertia is continuously available to maintain power system security, and the practical challenges of establishing efficient price discovery with a limited number of potential suppliers who have relatively fixed physical capabilities.

The key characteristics of spot and contract market approaches differ substantially in terms of price discovery, dispatch flexibility, and investment certainty. The spot market enables dynamic responses to changing system conditions but may create revenue uncertainty, while the contract market provides stable revenues but less operational flexibility. We explore the key features of these two market designs in table 4.2.

[37] Under the existing framework, this would involve TNSPs applying the regulatory investment test to evaluate network and non-network alternatives for providing inertia capacity. If non-network alternatives are chosen as the preferred option, then TNSPs would seek to competitively procure those services from non-networking providers, entering into contracts where prudent and efficient.

Table 4.2: Key features of spot markets and long-term contract markets

	Spot market	Long-term contract market
Promote efficient long-run investment in capacity (productive and dynamic efficiency)	More dynamic pricing encourages innovation in inertia supply. Uncertainty of revenue means that other financial tools are needed to manage long-term revenue risks. May lead to price volatility	Provides revenue certainty to encourage investment given market uncertainties and the upfront costs
Promote efficient short-run capacity availability (productive and allocative efficiency)	Provides price signals to optimise short-term availability. If there are only a small number of suppliers risks market power concerns	Promotes long-term availability. Short-run efficiency needs to be managed through alternative mechanisms. Scope for exercise of market power more limited given procurement method
Transactional and operating costs	Ongoing spot market operating costs and transactional costs for market participants	Simplified procurement method compared to spot market, with likely lower transactional and operating costs
Management of risks	May not provide sufficient investment signals given market price uncertainty	Provides greater certainty about the long-term supply

The choice between spot and contract market approaches ultimately depends on how well each design's characteristics align with the technical and economic features of inertia services. The following sections evaluate this alignment in detail, considering factors such as asset specificity, economies of scale, operational flexibility requirements, and investment timeframes.

4.3 Evaluation of minimum inertia service

The provision of minimum inertia services represents a fundamental requirement for power system security, with AEMO establishing requirements for minimum inertia service levels. Our assessment examines the economic and technical characteristics of these minimum inertia requirements to evaluate which market design is in principle, most appropriate for its efficient procurement.

4.3.1 Nature of the inertia service

AEMO defines minimum and secure operating levels of inertia based on technical requirements for maintaining power system security.[38] These levels represent threshold requirements that must be continuously available to ensure stable system operation.

The threshold levels are determined by fundamental power system characteristics, including:[39]

- the network configuration;
- the mix and location of connected generation;
- the size of credible contingency events; and
- other technical parameters affecting system security.

A key feature of these threshold requirements set by AEMO is their relative stability over time. While the minimum required levels may change in response to major system developments – such as the connection

[38] AEMO, *2023 Inertia Report*, December 2023, p 7. Also see section 2.2 of this report.

[39] AEMO, *2023 Inertia Report*, December 2023, pp 27-28.

of new renewable energy zones, retirement of synchronous generation, or changes to credible contingency events – such changes are generally predictable and occur over extended timeframes.

The ability to clearly specify inertia requirements, combined with the predictable nature of changes to these requirements, means that the procurement of minimum inertia services can feasibly occur through either:

- a spot market mechanism with well-defined technical requirements; or
- long-term procurement contracts with specified service levels.

This suggests that the nature of minimum inertia services does not inherently favour one market design over another. Rather, the choice between spot and contract markets should be driven by other economic characteristics examined in the following sections.

4.3.2 Need for revenue certainty for investors

The provision of minimum inertia services may require capital investment in long-lived assets. Synchronous condensers with flywheels, grid-forming batteries and repurposed synchronous generators are examples of technologies that require upfront investment to ensure continuous availability of inertia.

The capital costs and long asset lives associated with providing inertia capacity through these technologies creates a need for investors to have reasonable certainty over future revenues. This revenue certainty is particularly important given that some of these investments are largely specific to providing system security services.

A key challenge with implementing a spot market for minimum inertia services is the absence of historical price discovery and forward price signals. While secondary markets (such as hedge contracts) could theoretically develop over time to provide revenue certainty, there would likely be an extended period where investment signals remain weak or unclear. This uncertainty could delay or deter efficient investment in technologies providing minimum inertia services, particularly in the near term.

In contrast, long-term procurement contracts provide upfront revenue certainty that better aligns with the investment profile of inertia technologies. By specifying availability payments over extended periods, long-term contracts allow investors to manage technology-specific risks and support efficient financing of capital investments. This suggests that a long-term contracting approach may be more effective at promoting timely investment in technologies required for minimum inertia services.

4.3.3 Likely extent of competition in supply of inertia services

The technological diversity in providing minimum inertia services creates the potential for effective competition between suppliers. Multiple established and emerging technologies can meet the technical requirements for providing inertia. This diversity suggests that no single technology or provider is likely to dominate the market over the medium to long term, particularly once confidence in emerging technologies has been developed.

Competition between alternative technologies and providers is likely to be sufficient to mitigate concerns regarding market power. The ability of different technologies to serve as effective substitutes, combined with relatively low barriers to entry for some technologies like grid-forming batteries, means that individual suppliers would likely face competitive constraints in their bidding behaviour.

Our assessment therefore indicates that competitive dynamics would not preclude implementation of a spot market for minimum inertia services. However, while competition may be sufficient to support efficient price discovery in a spot market, this characteristic alone does not determine the optimal market design. Rather, it should be considered alongside other factors such as economic cost of under or over supply, investment requirements and operational efficiency.

4.3.4 Potential for efficiency gains

The transition away from synchronous generation in the NEM creates a fundamental need to establish arrangements that incentivise efficient investment in alternative technologies for providing minimum inertia services. The design of these arrangements must balance immediate system security requirements with longer-term incentives for cost reduction and technological innovation.

In the near term, we observe that synchronous condensers that TNSPs are currently expected to implement to meet system strength requirements in the near-term likely represent the most economic source of minimum inertia capacity. We understand that the incremental cost of adding inertia capability to these assets – through the addition of flywheels during initial construction – is relatively low.[40] This likely creates an opportunity to meet minimum inertia requirements efficiently by optimising the design of synchronous condensers that TNSPs are currently expected to build for system strength in the short-medium term.

However, our analysis indicates that the potential for more substantial efficiency gains is likely to emerge over a longer horizon, driven by two key developments:

- the exhaustion of opportunities to leverage synchronous condensers being built for system strength; and
- the maturation of alternative technologies, particularly grid-forming inverter-based resources, that may ultimately provide inertia services at lower cost.

This temporal dimension of efficiency opportunities has important implications for market design. While a spot market could theoretically provide stronger incentives for dynamic efficiency through continuous price signals, the likelihood that adding flywheels to synchronous condensers represents the most economic source of minimum inertia in the near term suggests limited scope for immediate productive or allocative efficiency gains from spot market arrangements.

Rather, the key challenge for market design is establishing frameworks that maintain incentives for technological development and innovation over the medium to long term, while ensuring efficient deployment of currently available technologies in the short term. This suggests value in incentivising contract procurement timeframes that align with the expected emergence of new technologies, thereby preserving competitive pressure for cost reduction while maintaining investment certainty.[41]

4.3.5 Economic cost of under or over supply

The economic consequences of insufficient minimum inertia are potentially severe, given its fundamental role in maintaining power system security. A shortfall in minimum inertia requirements could lead to system instability, cascading outages, or even widespread blackouts. These outcomes would impose substantial costs on electricity consumers and the broader economy through both direct interruption costs and flow-on effects to economic activity.

The asymmetric nature of these economic costs is a crucial consideration for market design. While oversupply of non-discretionary inertia involves some inefficiency through increased costs to consumers, these costs are relatively modest compared to the potential economic damage from undersupply. This asymmetry stems from the binary nature of system security – once minimum technical requirements are met, additional inertia provides limited incremental security benefits, although it can provide wider market benefits.

This cost characteristic strongly favours market arrangements that prioritise certainty of supply over short-term cost optimisation. The high economic cost of undersupply, combined with the relatively low cost of maintaining some redundancy in inertia provision, suggests that market designs should err on the side of

[40] AER, *The efficient management of system strength framework*, AER draft guidance, October 2024, p 31.

[41] For example, it may be that TNSPs are required to take into account the potential for technological development in developing a contracting strategy.

ensuring minimum inertia requirements are consistently met, even if this results in some degree of oversupply.

4.3.6 Assessment summary

Our assessment of market designs for minimum inertia services reveals a fundamental tension between two key objectives:

- ensuring certainty of supply to avoid potentially severe economic costs from system security risks; and
- promoting dynamic efficiency through price signals that encourage technological innovation and cost reduction over time.

While a spot market could theoretically provide stronger incentives for innovation, our analysis suggests there are likely to be limited immediate benefits from such arrangements. This reflects current technological and cost characteristics, particularly the potential to meet minimum inertia requirements efficiently in the near term by adding flywheels to synchronous condensers built for system strength. The likelihood that this represents the most economic source of minimum inertia in the near term means that spot market arrangements are unlikely to deliver material productive or allocative efficiency gains.

The asymmetric nature of economic costs likely favours market arrangements that prioritise certainty of supply over short-term cost optimisation. While oversupply of minimum inertia involves the potential for some increased costs to consumers, these costs are likely to be relatively modest compared to the potential economic damage from undersupply.

We therefore conclude that a medium to long-term contracting framework represents, in-principle, the most appropriate market design for minimum inertia requirements.

This approach provides the certainty needed to support efficient investment while maintaining system security. However, the design of such arrangements must carefully consider contract duration. Procurement mechanisms should incentivise contract procurement timeframes that align with expected technological development cycles, thereby preserving competitive pressure from emerging technologies in future procurement rounds while providing sufficient revenue certainty for current investments.

This structured procurement approach strikes an appropriate balance between immediate system security requirements and longer-term efficiency objectives. It recognises both the current technological landscape and the potential for innovation, while ensuring frameworks remain responsive to evolving system needs and capabilities.

4.4 Evaluation of the operational top-up and additional inertia services

The technical and economic characteristics of operational top-up and additional inertia services differ fundamentally from minimum inertia requirements, particularly in terms of substitutability with frequency control services and the consequences of under-provision. In this section, we consider and evaluate these characteristics as relevant to a choice of market design for operational top-up and additional inertia services.

4.4.1 Nature of the inertia service

The demand for operational top-up and additional inertia services arises from distinct operational circumstances that create opportunities for economic trade-offs in managing power system stability. Unlike minimum inertia service which is critical for maintaining basic system security, operational top-up and additional inertia provides market benefits through two primary mechanisms.

The first demand driver comes from the ability to substitute additional inertia for FFR services. Above the minimum levels, there exists a technical relationship between inertia and FFR that allows these services to be operationally substituted while maintaining frequency stability. This creates opportunities to optimise the provision of these services based on their relative costs in operational timeframes.

The second source of demand arises during operational conditions where available inertia falls below desired system security levels. In these circumstances, AEMO must currently employ alternative mechanisms such as adjustments to the contingency size or the issuing of directions to generators to maintain power system stability. Both mechanisms impose economic costs on the market – either through out-of-merit-order dispatch or by constraining the operation of generating units. Operational top-up inertia services could potentially avoid these costs by providing a market-based solution to address temporary shortfalls.

The ability to clearly define and operationalise these economic trade-offs is crucial for establishing a workable market for operational top-up and additional inertia services. This requires developing systems and processes that can:

- quantify the technical substitutability between inertia and FFR services above minimum threshold levels;
- calculate the costs of alternative mechanisms for managing system security;
- determine efficient price signals that reflect the economic value of operational top-up and additional inertia in different operational circumstances; and
- enable dynamic optimisation of inertia provision against other frequency control services.

It will be important to consider in further depth how feasible it is to develop the necessary systems to enable these trade-offs to be practically incorporated into operational dispatch processes. For the purposes of our evaluation, we have assumed that this is feasible. This means that our conclusions are dependent on this outcome.

It follows from this assumption that we assume that operational top-up and additional inertia services can be well-defined as a distinct market product, separate from minimum threshold inertia requirements.

The ability to clearly define the service and quantify its economic value is a crucial precondition for establishing efficient market arrangements. This characteristic of additional inertia services contrasts with minimum threshold inertia, where the focus is on ensuring the service is continuously available to maintain system security rather than optimising its provision based on economic trade-offs.

4.4.2 Need for revenue certainty for investors

The need for revenue certainty to support investment in technologies to provide incremental inertia services differs materially from that required for minimum inertia. We expect that demand for incremental inertia services is likely to fluctuate with market conditions and may often be zero. Due to this variable nature, these services are likely to be provided opportunistically by existing or planned facilities with inertia capabilities, rather than through new dedicated investments.

This opportunistic provision could come from various sources including:

- synchronous generators varying their commitment decisions; and
- batteries with grid-forming capabilities managing their headroom/foot-room.

As a result, the business case for investing in inertia-providing technologies is less likely to depend on revenue certainty from incremental inertia services alone. Rather, these capabilities are more likely to be developed as part of broader investment decisions considering multiple value streams including energy arbitrage, FCAS provision, and system strength services.

Over time, as the market for incremental inertia services matures and price discovery improves, secondary markets may naturally emerge to provide additional revenue certainty for investors. These could take various forms such as:

- financial derivatives to hedge inertia price exposure;

- bilateral contracts between inertia providers and market participants; or
- insurance products covering inertia revenue streams.

However, the development of such secondary markets is not a prerequisite for establishing a spot market for incremental inertia services, given the expected opportunistic nature of supply and the existence of multiple alternative revenue streams for most providers.

4.4.3 Likely extent of competition in supply of inertia services

The market for incremental inertia services is likely to feature robust competition due to both direct competition between inertia providers and indirect competition from substitute services. This competitive dynamic arises from two key factors.

First, various technologies can provide incremental inertia services, including over time future emerging technologies as they become commercially viable.

Second, and importantly, the substitutability between inertia and other frequency control services above minimum threshold levels creates effective competition from alternative services, particularly fast frequency response (FFR) providers.

This substitutability means that any attempt to exercise market power in providing incremental inertia services would likely be constrained by AEMO switching to alternative inertia technologies, frequency control services or system security approaches. The presence of these substitutes effectively expands the pool of competitors beyond just direct inertia providers.

The combination of multiple technology options for providing inertia and competition from substitute services suggests that market power concerns are unlikely to be a significant barrier to establishing an efficient spot market for incremental inertia services.

4.4.4 Potential for efficiency gains

The establishment of a market mechanism for incremental inertia services presents the potential for opportunities for efficiency gains through possible improved allocation of resources and optimisation of service provision. These potential efficiency gains arise primarily through two channels.

The first comes from allocative efficiency, by ensuring that the mix of frequency control services deployed at any time minimises total system costs while maintaining security requirements. Since incremental inertia can substitute at the margin for FFR and other frequency control services above minimum threshold levels, a market mechanism could enable:

- dynamic trade-offs between inertia and FFR based on relative costs;
- optimisation of the overall frequency control service mix over time;
- more efficient unit commitment decisions by synchronous generators; and/or
- reduced reliance on directions and other intervention mechanisms.

The second category relates to productive efficiency, by incentivising the lowest-cost provision of frequency control services over time. Market-based price signals could:

- encourage existing providers to lower their costs of making inertia available;
- drive innovation in how grid-forming batteries and other technologies provide frequency response; and/or
- support efficient investment decisions in multi-purpose assets that can provide both inertia and other services.

The magnitude of these efficiency gains will depend critically on:

- the cost differential between incremental inertia and frequency control services;
- the transaction costs associated with establishing and operating the market mechanism; and
- the ability of the market design to support efficient co-optimisation between services.

This analysis suggests that there is in-principle an opportunity to achieve allocative and productive efficiency gains, particularly as the power system continues to transition and the relationship between different frequency control services evolves. However, whether this is worth pursuing requires a careful consideration of the expected market benefits and how these compares to the costs of establishing and operating a preferred market mechanism.

4.4.5 Economic cost of under or over supply

The economic consequences of under or over supply of incremental inertia services differ fundamentally from those associated with minimum threshold inertia. Given the opportunistic nature of incremental inertia provision, any imbalances primarily result in efficiency losses rather than system security risks.

In the case of undersupply, the economic costs manifest as foregone efficiency gains, such as:

- missed opportunities to reduce FFR costs through substitution with potentially lower-cost inertia;
- higher-than-necessary costs from out-of-merit-order dispatch through directions; and
- suboptimal unit commitment decisions due to contingency size management.

Conversely, oversupply of incremental inertia would result in potentially relatively minor efficiency losses through:

- unnecessary commitment of synchronous generation for inertia provision;
- excessive holding of headroom/foot-room by batteries or other providers; and
- suboptimal allocation between inertia and frequency control services.

Importantly, neither under nor oversupply of incremental inertia services threatens system security, since minimum inertia capacity is managed separately and there is the opportunity for AEMO to use other instruments such as generator directions. This means that the economic consequences of temporary imbalances are relatively modest and self-correcting through normal market and regulatory processes.

Given this characterisation of the economic costs, we do not consider the risks of under or oversupply to be a determining factor in selecting an appropriate market design for incremental inertia services. This contrasts sharply with minimum threshold inertia, where the severe consequences of undersupply make supply certainty a crucial consideration in market design.

4.4.6 Assessment summary

Our assessment of the economic characteristics of incremental inertia services suggests that neither a spot market nor a long-term contract market holds a clear theoretical advantage. The key characteristics we have evaluated – including service definition, competition, efficiency opportunities, and consequences of imbalances – do not decisively favour one market design over the other.

This conclusion implies that the choice of market design should be primarily driven by practical considerations, particularly the relative costs of implementing and operating different market designs. The key decision criterion becomes whether the expected market benefits exceed the costs of implementation for any given design. These costs are likely to differ materially between:

- spot market implementation costs, including:
  - systems development for real-time co-optimisation;

  - integration with existing dispatch processes;
  - price formation and settlement mechanisms; and
  - market monitoring and compliance frameworks; and
- long-term contract market costs, including:
  - tender process development and administration;
  - contract management systems; and
  - operational mechanisms to call on contracted services.

Given this, we recommend that the selection of market design for incremental inertia services should focus on identifying the lowest-cost design capable of delivering the anticipated efficiency benefits.

To support this, we have quantified the anticipated market benefits of providing incremental inertia services which can then be compared against the expected market implementation and operational costs.

This practical, cost-focused approach to market design selection recognises that while both spot and contract markets could theoretically support efficient outcomes, the optimal choice depends on minimising the transaction costs associated with establishing and operating the chosen market design.

5. Estimating the economic benefits of operational top-up and additional inertia services

To inform an assessment of the appropriate market design for inertia services above the level available through energy dispatch, we quantify the potential economic benefits from optimising the use of inertia, FFR and other operational interventions to maintain system security during periods of low inertia.

As defined in section 3.1, inertia services above the level available through energy dispatch consist of two types – inertia addressing shortfall with respect to the minimum level in operational timeframes (ie, operational top-up inertia) and inertia above the operational minimum needs and above the level provided through energy dispatch, when this delivers economic benefits (ie, additional inertia).

In this section, we summarise our methodology and set out the key results of our analysis. Detailed description and additional sensitivity analysis are presented in appendices A1 and A3.

5.1 Overview of the approach

To quantify the economic benefits of inertia services above the level available through energy dispatch in the NEM, we have identified four key categories of benefit, ie:

- for operational top-up inertia:
  - economic benefits arising from avoiding contingency size reductions (*'contingency size change'* benefit);
  - economic benefits arising from reducing the need to direct generators to synchronise (*'directions reduction'* benefit);
- for additional inertia:
  - economic benefits arising from substituting between additional inertia and FFR (*'inertia – FFR optimisation'* benefit); and
  - economic benefits arising from alleviating RoCoF-induced constraints imposed on interconnector flows and energy generation ('*RoCoF constraints alleviation*' benefit).

In the remainder of this section, we set out a high-level description of our methodology to estimate the benefits in each category.

5.1.1 Methodology to estimate the 'inertia – FFR optimisation' benefit

We understand that above the minimum levels, there exists a technical relationship between inertia and FFR that allows these services to be operationally substituted while maintaining frequency stability.[42] Specifically, when the amount of inertia above the minimum levels increases, there is less need for FFR at a given contingency size without compromising frequency stability. Such substitutability between inertia above minimum levels and FFR creates opportunities to optimise the provision of these services (based on their relative costs) to result in least-cost outcomes in operational timeframes.

[42] The potential for substitutability between inertia and FFR only arises within certain ranges. For instance, we understand that there is a minimum level of inertia needed in the power system to provide unique characteristics, which cannot be replaced by other services. To the extent that the quantification methodology captures the economic benefits of additional inertia above the minimum level, it is reasonable to consider the substitutability characteristics.

As current synchronous inertia capacity reduces over time due to the retirement of synchronous generators, there may be a need to increase the level of FFR to manage power system stability, which leads to an increase in the total cost of providing FFR. Some of the increased costs in FFR might be avoided through providing additional inertia. The *'inertia – FFR optimisation'* benefit arises from opportunities to attain a least-cost combination of FFR and inertia in operational timeframes through co-optimisation based on relative costs.

To capture these potential benefits, we have developed a simplified optimisation model to operate the inertia – FFR trade-off based on assumptions of fixed and variable costs for inertia and 1-second raise FCAS. The model chooses an optimal quantity of inertia and 1-second raise FCAS for each five-minute interval in order to meet a certain exogeneous amount of FFR requirement to maintain system security. This modelling framework allows us to compare the total inertia and 1-second raise FCAS costs between two scenarios, ie:

- 'without inertia' scenario – in which additional inertia is not available and whole of FFR requirements would be met by 1-second raise FCAS; and
- 'with inertia' scenario – in which additional inertia is available, reducing the quantity of 1-second raise FCAS compared to the 'without inertia' scenario.

If the cost of providing additional inertia is less than that of 1-second raise FCAS, the total cost of meeting FFR requirements in the 'with inertia' scenario would be lower than the 'without inertia' scenario. The decrease in the total cost of meeting FFR requirements is the economic benefit of additional inertia arising from co-optimising with 1-second raise FCAS to meet FFR requirements.

Fixed and variable costs of inertia and 1-second raise FCAS are critical assumptions in this assessment. However, these costs are highly challenging to estimate with certainty. Our analysis of public information and data suggests an absence of definitive estimates of costs. This is because:

- in general, batteries are developed to provide a range of services (eg, energy and FCAS markets participation) – therefore it is unclear the extent to which capital costs would be attributable to a particular service only; and
- the variable cost of batteries is generally associated with the concept of opportunity costs (ie, foregone revenues from alternative services as a result of providing a particular service), which depends on forecast prices of these alternative services and is challenging to capture without a comprehensive wholesale market modelling approach.

Notwithstanding, we have adopted a range of assumptions and approaches to obtain preliminary cost estimates that are used as inputs in the economic benefits assessment. We highlight several key caveats underlying the cost estimates below:

- regarding fixed costs:
  - > the fixed cost of supplying inertia by IBRs is assumed to be 5 per cent of IBRs capital cost; and
  - > the fixed cost of supplying 1-second raise FCAS is assumed to be 50 per cent of IBRs capital cost.[43]
- regarding variable costs:[44]
  - > the variable cost of inertia is estimated by reference to foregone revenues in energy arbitraging as a result of supplying inertia (by applying a battery optimisation framework); and
  - > the variable cost of 1-second raise FCAS is estimated by analysing historical bids data submitted by 1-second raise FCAS providers.

[43] We undertake a range of alternative assumptions on the proportion of IBRs capital cost attributable to 1-second raise FCAS.

[44] Detailed methodologies for estimating these costs are described in appendices A2 and A1.1 respectively.

We believe that our estimated variable cost of inertia is likely to be conservative because the approach does not account for potential lost revenues from FCAS markets.

Regarding the variable cost of 1-second raise FCAS, we note that historical bids by suppliers may represent an upper end of variable costs. However, we consider that using historical bid information is helpful for informing the likely order of magnitude of variable costs for these services. To alleviate potential concerns about an over-estimation of these costs from historical bid information, we have taken the lowest bid price (across the sample historical 5-minute data) for each quantity of FCAS to construct a cost curve for 1-second raise FCAS.

Despite the simplified and assumptions-driven approach we have taken, we believe that the costs we have estimated are reasonable considering our objective to understand the order of magnitude of the economic benefits. We describe the methodology for calibrating 1-second raise FCAS and inertia costs in appendices A2 and A1.1 respectively.

Despite adopting conversative assumptions to estimate costs, we understand there remains a residual degree of uncertainty. Therefore, we undertake a range of sensitivity analyses to examine the impact of alternative cost assumptions on the order of magnitude estimates of economic benefits.

In particular, we examine three alternative cost assumptions for inertia variable costs (ie, low, average and high). The low and high cases represent a 90 per cent reduction and increase in the average cost assumption, which is estimated by applying a battery optimisation framework as mentioned above (and described in appendix A2).

Further, we examine two scenarios with respect to the market value of 1-second raise FCAS in the future, ie:

- market value of 1-second raise FCAS is assumed to remain steady or decrease over time;[45] and
- market value of 1-second raise FCAS is assumed to increase over time.

We note that the scenarios do not reflect our forecast of market values for these services in the future. Rather, the scenarios are intended to highlight that the order of magnitude of the economic benefits is driven by expectations of the future market value of 1-second raise FCAS, which determines the upper bound with respect to the extent to which additional inertia could substitute for 1-second raise FCAS.

Finally, our methodology assumes that it is technically feasible to optimise between inertia and 1-second raise FCAS. Should the trade-off between inertia and 1-second raise FCAS not be technically feasible, the economic benefits estimated by our methodology would not be realised.

5.1.2 Methodology to estimate the 'RoCoF constraint alleviation' benefit

We understand that inertia-related variables are present in a number of constraints in the NEM dispatch engine (ie, NEMDE). For instance, we identify the following constraints[46] with inertia variables on the right-hand side (RHS):

$$Heywood\ Flow\ (MW) \leq 0.04\ x\ RoCoF\ Limit\ (Hz) x\ SA\ inertia\ (MWs)$$

$$Tas\ Wind\ (MW) + Basslink\ Import\ (MW) \leq 0.17\ x\ TAS\ inertia\ (MWs)$$

[45] In this scenario, costs of 1-second raise FCAS are assumed to decrease at a rate of eight per cent per annum, which is derived from AEMO's projections of battery capital costs between 2024 and 2030. These projections are used in the Integrated System Planning 2024.

[46] These constraints are named 'V_S_NIL_ROCOF' and 'T_ROCOF_3' in NEMDE. We note there are other constraints with inertia variables on the RHS. However, the RHS also contains other non-inertia variables, and therefore it is outside the scope of this initial order of magnitude assessment to disentangle the incremental total system costs associated with the inertia-related variables only in these constraints.

In these constraints, the ‘SA inertia‘ and ‘TAS inertia’ terms on the RHS restrict the magnitude of flow over Heywood (for the first constraint) and Tasmanian wind and import over Basslink (for the second constraint) on the left-hand side (LHS). In other words, interconnector flows across Heywood and lower cost generation sources in Tasmania and Victoria are constrained when there are low levels of inertia in South Australia and Tasmania.

It follows that when flows on Heywood are constrained down due to low levels of inertia in South Australia, providing additional inertia in South Australia would allow flows on Heywood to increase, unlocking lower cost generation resources in Victoria in operational timeframes. Similarly, when wind output in Tasmania or imports on Basslink are constrained down due to low levels of inertia in Tasmania, providing additional inertia in Tasmania would unlock more lower cost generation resources to the grid. In both circumstances, total system costs would be reduced.

Subject to how often these constraints bind in the future, there may be material economic benefits arising from providing additional inertia to unlock lower cost generation resources in the NEM. The economic benefits are estimated by reference to the decrease in total system costs when additional inertia is provided in South Australia and Tasmania.

To estimate this benefit, we analyse AEMO’s Electricity Data Model that contains historical outcomes of constraints in NEMDE at five-minute intervals. The database contains information on whether a constraint was binding in each five-minute interval, and the impact on the total system costs when the RHS of a constraint increases by 1 unit.[47] These data allow us to quantify two key metrics, ie:

- how often each of these constraints bound in the past; and
- the decrease in total system costs, on average, when the inertia variables on the RHS are increased by 1 MWs.

The economic benefit is estimated by reference to the latter metrics (expressed on a per-MWs basis), whereas the former metrics informs the potential size of benefits that might be realised.

We note that in general, constraints in the NEM dispatch engine might change over time as conditions in the power system change. If these constraints no longer bind in the future, the estimated ‘RoCoF constraint alleviation’ benefits would not be realised.

5.1.3 Methodology to estimate the ‘contingency size change’ benefit

The ‘*contingency size change*’ benefit results from the potential for operational top-up inertia to reduce the need for AEMO to reduce the output of the largest generating unit (ie, to reduce contingency size) to address an operational inertia shortfall in the power system.

The benefit of operational top-up inertia in this aspect is equivalent to the avoided cost of reducing contingency sizes, offset by the incremental cost of providing operational top-up inertia available to the power system. We note that our methodology captures the economic benefits arising from opportunistic inertia increases from existing investments.

To estimate the avoided cost of reducing contingency sizes, we analyse historical wholesale market data in financial year 2023-24 to understand how often the largest generating units, at each dispatch interval, were constrained in its generation output. We then test different assumptions[48] about what proportion of these ‘constrained’ instances is attributed to addressing operational inertia shortfalls. The increase in total system

[47] This information is available in column ‘MARGINALVALUE’ in table dispatch constraint in the AEMO’s Electricity Data Model. The marginal value is the marginal cost of the constraint equation calculated by NEMDE. If there was a change in the constraint equation RHS by 1 unit the marginal value represents the change in cost to the objective function.

[48] The reason for testing different assumptions lies in the fact it is challenging to identify the exact instances in the past when AEMO reduced contingency sizes to address operational inertia shortfalls. The challenge stems from data limitations.

cost resulting from calling on more expensive generation sources to fill the reduced output of the largest generating unit is then our estimate of the avoided cost of reducing contingency size.[49]

To estimate the cost of providing operational top-up inertia, we apply the cost estimates (as presented in table 3.1) to the quantum of inertia that is equivalent to the reduction in inertia capacity resulting from reducing contingency size.

The '*contingency size change*' benefit is estimated as the avoided cost of reducing contingency sizes, less the cost of increasing inertia.

An important consideration when interpreting these results, is the relationship between the assumption regarding how often contingency sizes are reduced to address operational shortfalls and the estimated economic benefits. Given uncertainty about the likely future frequency of contingency changes, we estimate a range of benefits by considering a range of assumptions regarding how often contingency sizes are reduced in the future. This provides stakeholders with a clearer understanding as to how these benefits might very depending on expectations about the likely incidence of contingency size changes in the future.

5.1.4 Methodology to estimate the 'directions reduction' benefit

'Directions reduction' benefits arise from the potential opportunity to reduce the number of directions issued by AEMO to address operational inertia shortfalls by making more inertia available to the power system.

The benefit of operational top-up inertia in this circumstance is captured as the avoided cost of directions, offset by the cost of providing operational top-up inertia directly attributable to avoiding directions.

To estimate the avoided cost of directions, we analyse historical direction costs from South Australia as a baseline for understanding the order of magnitude of costs when generators are directed to dispatch for system security purposes. Specifically, we examine the total compensation (which includes additional compensation) paid to directed generators, which we believe is a reasonable estimate for direction costs across the NEM, acknowledging that each direction can vary.

We analyse compensation data published by AEMO regarding directions in South Australia between April 2023 and March 2024.[50] The data do not specify which directions were issued to address inertia shortfalls.[51] Therefore, we examine the whole range of direction costs in order to understand the full extent of variability. The variability in the analysis outcomes will be wider than what it would be should only inertia-related directions were examined, which we consider is a conservative approach for the purpose of order of magnitude assessment.

The compensation data also provide the generating unit that was directed to dispatch for each direction. This allows us to directly estimate the quantum of inertia that was provided in each direction.[52]

To estimate the cost of providing operational top-up inertia, we apply the cost estimates (as presented in table 3.1) to the quantum of inertia identified in the preceding step. Similar to the 'contingency size change' benefit, our methodology captures the economic benefits arising from opportunistic inertia increases from existing investments.

[49] We apply wholesale energy prices as the proxy for the costs of the most expensive generation sources to fill the reduced output of the largest generating unit. This approach provides an order of magnitude assessment of the related costs. A long-handed approach to estimate the cost of the alternative generation sources require some form of counterfactual analysis (eg, through wholesale market modelling), which we consider out of scope for an order of magnitude assessment.

[50] The data can be accessed at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/market-event-reports.

[51] Reasons for directions specified in the data are either 'system strength' or 'system security'.

[52] H constants are applied to convert generation capacity to MWs of inertia provided. H constants are sourced from AEMC generator information.

The '*directions reduction*' benefit is then estimated as the avoided cost of directions, less the cost of providing operational top-up inertia services.

We present the benefit estimates for this category on a 'per direction' basis. To understand the potential order of magnitude size of the '*directions reduction*' benefit across the NEM in the future, we will present a range of total benefits corresponding to a range of assumed number of directions in the future. We note that this does not reflect our expectations of the number of directions in the NEM in the future. Rather, it highlights that the economic benefits depend on how often directions are expected to be used in the future to address operational inertia shortfalls.

In summary, our methodology for estimating economic benefits examines multiple benefit categories and incorporates sensitivity analysis of key assumptions, enabling us to understand the potential range of economic benefits from optimising inertia provision across operational timeframes. By evaluating outcomes under various future scenarios, we can assess how these benefits might shift under different conditions. Our transparent approach to assumptions and analysis provides meaningful insights into the relative scale and importance of different benefit sources, creating a robust framework for understanding the economic value of optimised inertia management in power systems.

We provide a more detailed description of our methodologies in appendix A1.

5.2 Estimates of economic benefits of operational top-up and additional inertia services are sensitive to a range of assumptions

Our analysis suggests that the range of benefits associated with providing operational top-up and additional inertia services in the NEM across the four benefit categories is as follows:[53]

- for additional inertia services:
  - the '*inertia – FFR optimisation*' benefit increases from $7.7 million in 2024 to $30 million in 2033 at the upper end;
  - the '*RoCoF constraint alleviation*' benefit ranges from $2 to $20 per MWs of additional inertia in South Australia, and from $5 to $355 per MWs of additional inertia in Tasmania during low inertia periods;
- for operational top-up inertia services:
  - the '*contingency size change*' benefit ranges from $0.7 million and $7.2 million per year; and
  - the '*directions reduction*' benefit averages to $1.8 million per direction avoided.

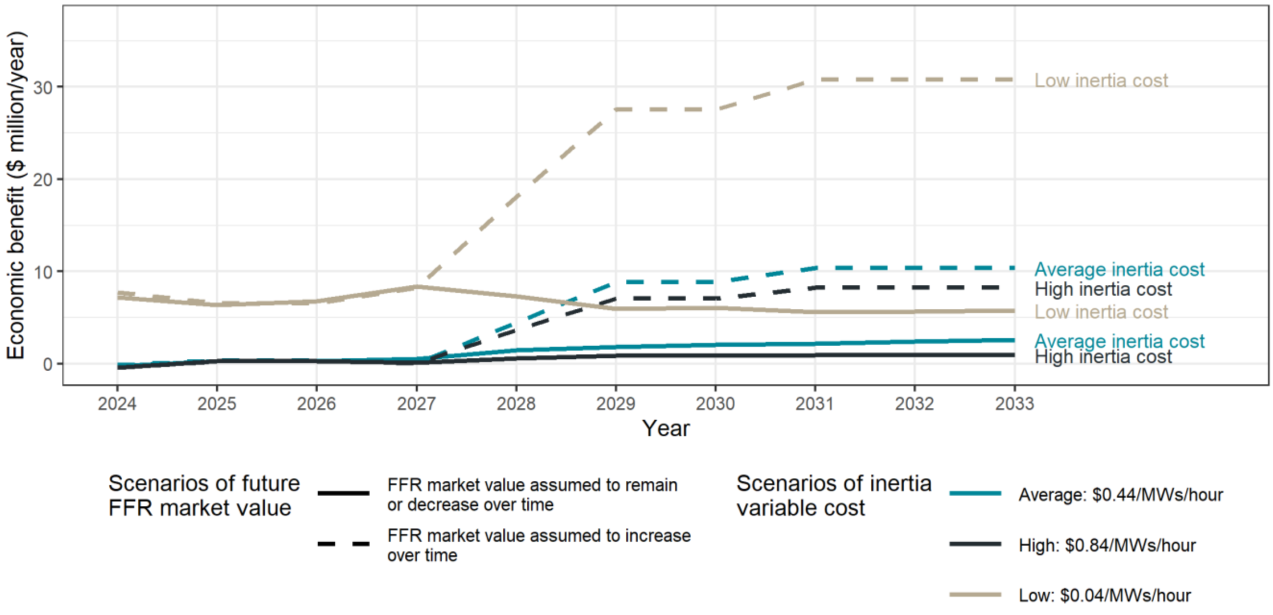
In the remainder of this section, we describe the results for each benefit category in greater detail.

5.2.1 Estimates of the 'inertia – FFR optimisation' benefit

Figure 5.1 presents the economic benefits of additional inertia arising from reducing the costs of providing 1-second raise FCAS to meet FFR requirements. As described in section 5.1.1, we examine three alternative cost assumptions for inertia variable costs (ie, low, average and high) and two scenarios for market value of FFR in the future. We explained in section 5.1.1 that these scenarios do not reflect our forecast for the future.

[53] All values are expressed in 2024 dollar terms.

Figure 5.1: Estimates of '*inertia – FFR optimisation*' benefits across scenarios of future FFR market value and inertia variable cost



Source: HoustonKemp analysis. The variability in economic benefits across the low, average and high inertia variable cost scenarios reflects the varying cost relativities between inertia and 1-second raise FCAS.
Note: Slight negative economic benefits are observed in the early years of the modelling horizon in the 'average' and 'high' inertia costs scenarios with FFR market value assumed to remain or decrease over time. This can be explained by the perfect foresight in the optimisation model. When more inertia is expected to substitute 1-second raise FCAS in the long term, an optimised outcome suggests that 1-second raise FCAS capacity would not be built up to the whole FFR requirements in the short term since they would give rise to unused capacity in the future. Instead, certain capacity of inertia would be built in the short term. The higher cost in this outcome (compared to meeting the whole FFR requirement with 1-second raise FCAS) in the short term is offset by the higher cost savings due to inertia substitution in the long term.

At the upper end, the 'inertia – FFR optimisation' benefits are estimated to range from $7.7 million in 2024 to $30 million in 2033.

The results highlight a number of key dynamics when it comes to understanding the range of economic benefits across scenarios and over time. By way of summary:

- economic benefits would potentially increase over time when the value of the 1-second raise FCAS market is expected to grow over time (ie, the time dimension of economic benefits); and
- economic benefits would be higher if the costs of providing inertia is lower than the average we have assumed (ie, the impact of inertia – FFR cost relativity on economic benefits);

Below we explain these key dynamics in greater detail.

The time dimension of economic benefits

Economic benefits would potentially increase over time when the value of the 1-second raise FCAS market is expected to grow over time. This is demonstrated by the dashed lines in figure 5.1, in which value of the 1-second raise FCAS market is found to grow in the future as FFR requirement increases[54] (due to reduced synchronous inertia capacity).

[54] The rate of increase in FFR requirement is proportionate to the rate of reduction in the forecast inertia capacity available to the power system, as presented in Figure 2.2.

The material increase in 2028 reflects the start of substantial decreases in synchronous inertia capacity (as presented in figure 2.2), which increases FFR requirements and the extent to which additional inertia could substitute 1-second raise FCAS.

In an alternative scenario when the value of the 1-second raise FCAS market does not grow in the future, the opportunities for additional inertia to reduce the value of 1-second raise FCAS market would be more limited, which might result in the economic benefits being towards the lower-bound estimates. This is demonstrated by the solid lines in figure 5.1. In these scenarios, costs are assumed to decrease at a higher rate than the increase in demand in the future, which results in decreased value of the 1-second raise FCAS market. This reflects a market that grows in line with demand, ie, increased demand induces more entrance of providers, which puts downward pressure on prices for these services.

In practice, we would expect the 1-second raise FCAS market to grow in line with rising demand. However, the extent of growth is uncertain, with a no-growth scenario being an extreme. Our analysis highlights that there may be opportunities for additional inertia to substitute for 1-second raise FCAS and lower costs of meeting FFR requirements. The magnitude of economic benefits depends on expectations of market value for 1-second raise FCAS in the future.

The impact of inertia – FFR cost relativity on economic benefits

Since the economic benefits capture the extent to which additional inertia could substitute for 1-second raise FCAS to obtain optimal least-cost outcomes, the lower the cost of additional inertia, the higher the economic benefits. This can be seen in the range of economic benefits across scenarios of inertia variable costs in our analysis, given a particular assumption about future FFR market value (ie, comparing across the solid lines, or across the dashed lines in figure 5.1).

In particular, when FFR market value is assumed to grow over time, the economic benefits are estimated to be approximately:[55]

- $20 million on average per year when the cost of providing inertia is assumed to be low (at $0.04/MWs/hour); and
- $4 million on average per year when the cost of providing inertia is assumed to be high (at $0.84/MWs/hour).

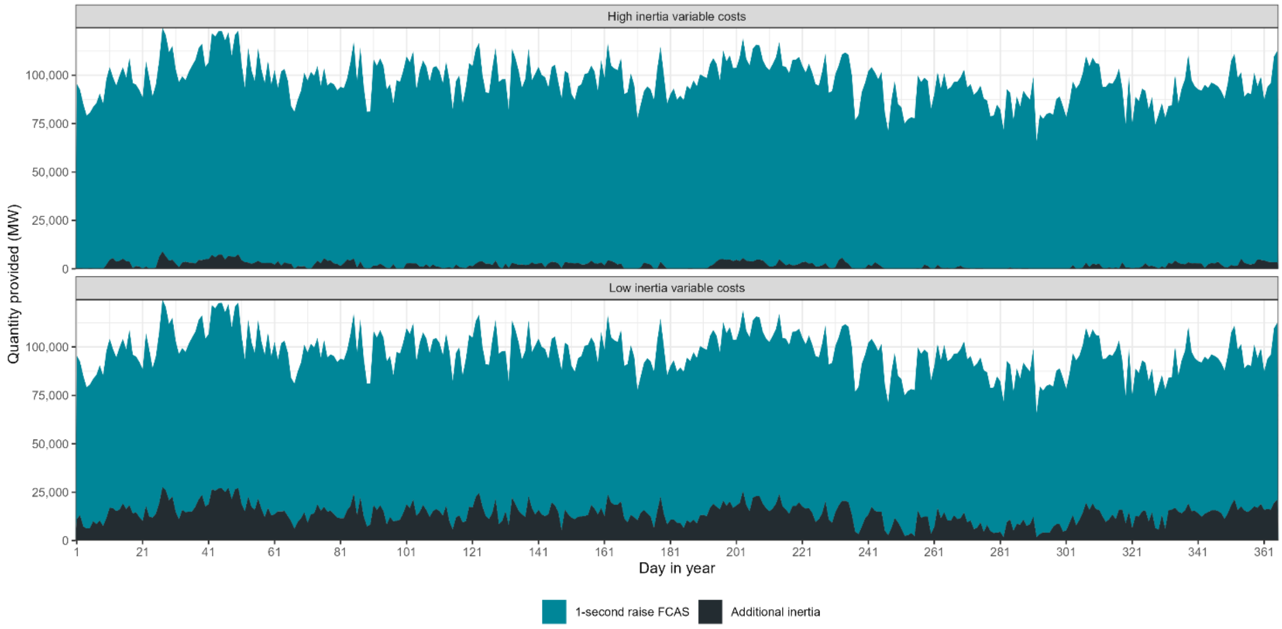
These numbers would increase to $6.5 million and $0.5 million respectively when FFR market value is assumed to remain or decrease over time. In either case, the analysis highlights that the economic benefits are higher when the cost of inertia is lower.

We set out the underlying cost assumptions and caveats in detail in section 5.1.1.

We visualise in figure 5.2 the extent to which additional inertia could substitute for 1-second raise FCAS based on cost differentials. When the cost differential is higher, more additional inertia could avoid more 1-second raise FCAS, leading to higher economic benefits.

[55] Economic benefits are averaged across years (between 2024 and 2033) for the purpose of comparison.

Figure 5.2: Trade-off quantity of additional inertia and 1-second raise FCAS in 2033 – scenarios of low and high inertia variable costs



Note: Values on the y-axis represent the quantity of 1-second raise FCAS and inertia provided to meet FFR requirements (measured in MW). Inertia (measured in MWs) is converted to MW by applying the slope of the trade-off curve (ie, 1 MWs of inertia is equivalent to 0.004667 MW of 1-second raise FCAS). This trade-off rate is derived from the AEMO's presentation of the relationship between inertia and uncapped 1-second raise FCAS in a frequency monitoring report (see: AEMO, Frequency monitoring – quarter 2 2024, August 2024, pp 11 and 12).

Our analysis suggests that based on the assumed cost inputs for inertia and 1-second raise FCAS, there is potentially a small amount of additional inertia that could substitute for 1-second raise FCAS at the margins.

By way of summary, this analysis highlights that the potential economic benefits arising from co-optimising with 1-second raise FCAS are sensitive to assumptions of current costs and how these costs evolve in the future. At the upper end, the economic benefits are estimated to range from $7.7 million in 2024 to $30 million in 2033. Through sensitivity analysis, we have demonstrated that when cost assumptions change, the economic benefits are likely to change as well. However, the dynamics of the underlying drivers continue to apply, ie:

- economic benefits would increase over time if the value of the 1-second raise FCAS market is expected to grow over time (ie, the time dimension of economic benefits); and
- economic benefits would be higher if the cost of providing inertia is lower (ie, the impact of inertia – FFR cost relativity on economic benefits).

Understanding these dynamics provide a rationale framework that could be applied when alternative cost assumptions are made.

5.2.2 Estimates of the 'RoCoF constraint alleviation' benefit

Our analysis of historical constraint outcomes suggests that there are potential benefits:[56]

- between $2 and $20 per MWs of additional inertia in South Australia during constrained periods; and
- between $5 and $355 per MWs of additional inertia in Tasmania during constrained periods.

[56] Values of economic benefits are expressed in 2024 dollar terms.

These ranges are obtained from analysing the average reduction in total system costs since financial year 2020-21. The reduction in total system costs is calculated by NEMDE, and published in AEMO's Electricity Data Model. Table 5.1 sets out the annual average reduction in total system costs on a per-MWs basis as well as the change in the frequency at which the examined constraints bound in the last four years.

Table 5.1: Estimates of 'RoCoF alleviation' benefit between 2021-22 and 2023-24

Year	SA RoCoF constraint		TAS RoCoF constraint	
	Frequency of binding	Economic benefit ($ per MWs during a constrained period)	Frequency of binding	Economic benefit ($ per MWs during a constrained period)
2021	3.4 per cent	$2 per MWs	0.0 per cent	$25 per MWs
2022	0.5 per cent	$15 per MWs	0.0 per cent	$5 per MWs
2023	0.2 per cent	$20 per MWs	0.4 per cent	$10 per MWs
2024	0.5 per cent	$5 per MWs	0.9 per cent	$355 per MWs

Note: Values of economic benefits are expressed in 2024 dollar terms. A constrained period refers to any five-minute period during which flows over Heywood are constrained due to low level of inertia in South Australia, or more efficient generation resources are constrained in the NEM due to low level of inertia in Tasmania.

We note that the estimated economic benefits in South Australia and Tasmania can only be realised during periods when flows over Heywood are constrained down, or Tasmanian wind output and/or import flows through Basslink are curtailed (ie, constrained periods). The 'frequency of binding' metrics provides insights into how often constrained periods arose, which informs the materiality of the total economic benefits.

In particular, we observe that the frequency of constrained Tasmanian wind output and/or import flows over Basslink has increased in the last four years, with total system cost potentially reduced by $355 on average for each additional unit of inertia in Tasmania in financial year 2023-24. This suggests that there is potentially material economic benefit arising from providing additional inertia in Tasmania.

The constraint in South Australia is expected to be alleviated when EnergyConnect stage two is commissioned.[57]

As mentioned previously, in general constraints in the NEM dispatch engine might change over time as conditions in the power system change. This highlights the nature of uncertainty as to whether economic benefits might be realised in the future. For instance, if the frequency of binding decreases or the constraints are removed completely, the realised economic benefits might decrease or equal to zero.

5.2.3 Estimates of the 'contingency size change' benefit

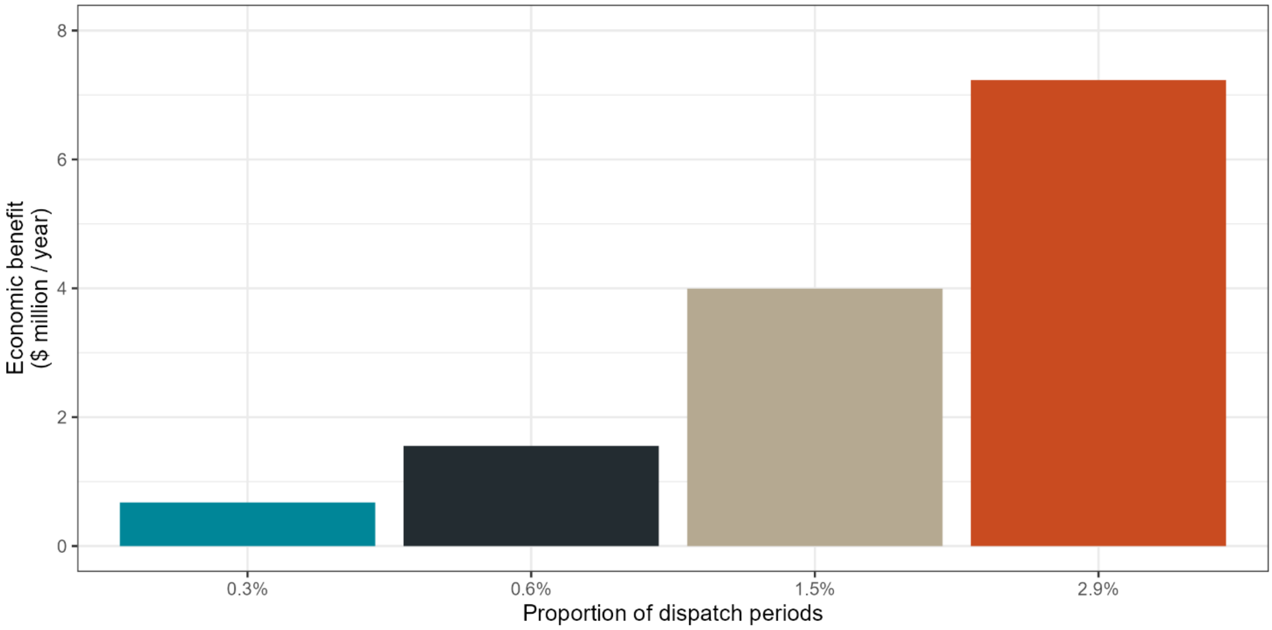
We estimate that using operational top-up inertia to avoid contingency size changes has the potential to deliver benefits of between $0.7 and $7.2 million each year depending on the frequency with which AEMO needs to make contingency size reductions in the future due to low system inertia – figure 5.3.

The size of the benefit will vary depending on the expected cost of providing inertia to avoid a contingency size change. Our estimate of benefits assumes an 'average' cost of providing inertia across the range of inertia technologies that we have considered.[58] However, the size of the benefits could increase (or decrease) by as much as four per cent if lower (or higher) cost inertia technologies are available.

[57] ElectraNet, 2024 transmission annual planning report, p 50. Available at https://www.electranet.com.au/wp-content/uploads/ElectraNet-2024-TAPR-3.pdf, accessed on 18 November 2024.

[58] Existing technologies that are assumed to provide operational top-up inertia services in this analysis include delayed/prolonged dispatch from synchronous generators (coal and gas), and IBRs.

Figure 5.3: Average estimates of '*contingency size change*' benefit



Source: HoustonKemp analysis. Estimates of benefits are obtained from assuming an 'average' cost of providing inertia across the range of inertia technologies that we have considered. These average costs are presented in table 3.1.The values on the x axis represents the proportion of dispatch periods in a year during which contingency sizes were changed to address operational inertia shortfalls. The values correspond to the four assumed frequencies (ie, one, two, five and ten per cent) applied to the pre-sampling periods obtained by narrowing dispatch periods down to instances where the largest generating unit is dispatching at lower-than-capacity level (see appendix A1.2 for detailed description of the methodology).

5.2.4 Estimates of the 'directions reduction' benefit

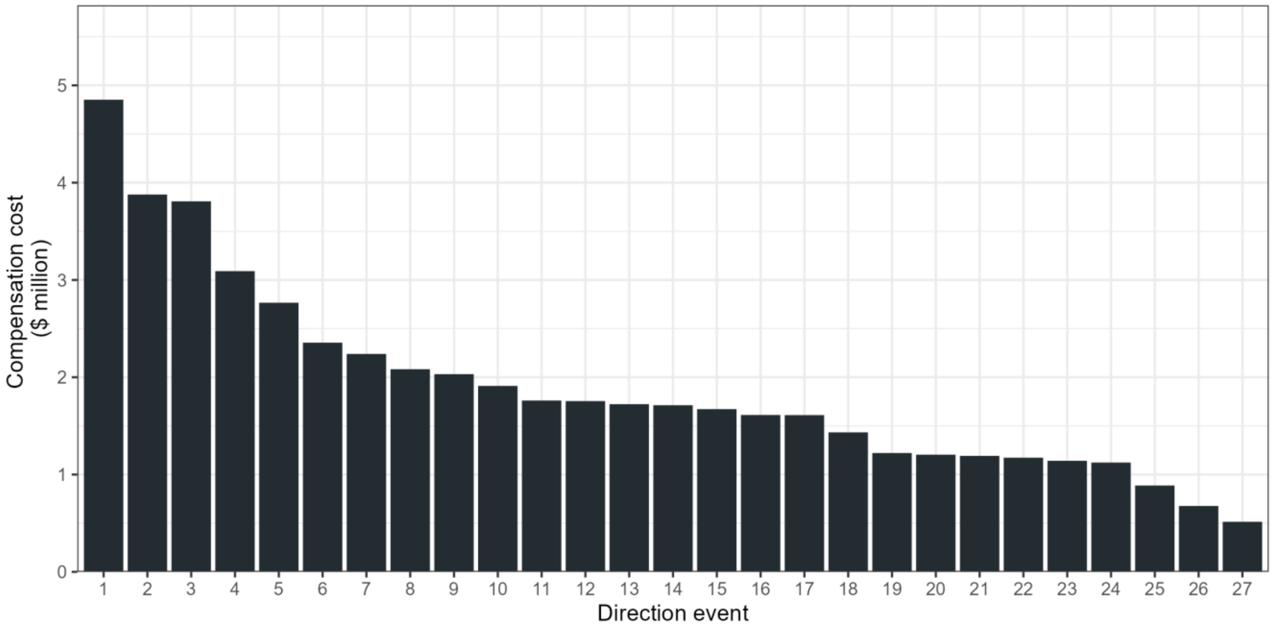
We estimate that the benefit of avoiding a direction likely ranges between $500,000 and $5 million, with a median and average being $1.7 million and $1.9 million respectively – figure 5.4. This distribution is based on the compensation costs for directions in South Australia for system strength and system security purposes between April 2023 and March 2024. The range reflects different lengths for a direction, and the operating costs of the generating unit being directed.

We acknowledge compensation costs depend on the nature of the directions, and potentially the location of the directed generating unit. However, we believe that this range reflects a reasonable estimate of costs for directions across the NEM.

On average, the benefit of avoiding directions is estimated to be $1.8 million per direction. This estimate is obtained by taking the average avoided direction cost of $1.9 million, offset by the total 'average' cost of providing operational top-up inertia across the range of inertia technologies that we have considered.[59] However, the size of the benefits could increase (or decrease) by as much as two per cent if lower (or higher) cost inertia technologies are available to deliver this benefit.

[59] See footnote 58.

Figure 5.4: Historical direction costs to directed gas generators in South Australia in April 2023 to March 2024 – in decreasing order



Note: 'Direction event' on the x-axis represents a numbering of events corresponding to decreasing direction costs in April 2023 to March 2024. Direction costs include directions compensation payment and additional compensation.
Source: HoustonKemp analysis of data published by AEMO, available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/market-event-reports.

The total size of the benefit depends on how many directions are expected to be issued in the NEM in the future to address operational inertia shortfalls. Table 5.2 sets out a number of illustrative examples of the total size of the benefit based on assumed numbers of directions per year across the NEM.

Table 5.2: Illustrative estimated 'directions reduction' benefits ($ million per year)

Number of directions in one year	Estimated 'directions reduction' benefits of operational top-up inertia ($ million)
2 directions	$3.6 million per year
5 directions	$9 million per year
10 directions	$18 million per year
20 directions	$36 million per year
30 directions	$54 million per year

Note: Total benefits are calculated based on the estimated benefit of $1.8 million per direction. Values are expressed in 2024 dollar terms.

5.3 Costs for a real-time spot market for operational top-up and additional inertia services

The costs for establishing and operating a real-time spot market for operational top-up and additional inertia are uncertain. In this section, we consider the costs of establishing the market, operating the market by AEMO, and costs for market participants.

5.3.1 Costs of establishing a real-time spot market

The implementation of a spot market for operational top-up and additional inertia services would require investment in market systems, processes and capabilities. While the likely costs for implementing such a market are uncertain, based on AEMO's experience implementing the 1-second FCAS markets at a cost of $4.3 million, [60] we believe it would be reasonable to assume that establishing an inertia spot market would likely cost between $5 million and $10 million, though precise implementation costs remain uncertain at this stage.

Our expectation of higher implementation costs compared to the 1-second FCAS markets reflects several factors.

The complex nature of inertia services presents unique technical challenges that will require careful consideration and system development. In particular, we expect that designing algorithms to effectively co-optimise inertia with energy dispatch and existing frequency control services will be more complex than the relatively straightforward addition of a new FCAS product. Additional technical complexities arise from the binary nature of inertia provision, the need to account for regional requirements during islanded conditions and ensuring secure system operation when dispatching incremental inertia. These challenges are likely to require more extensive market testing and system development than was needed for implementing the 1-second FCAS markets.

5.3.2 AEMO market operational costs

In addition, we expect that AEMO would incur ongoing operational costs to run the inertia spot market, which we estimate at $1 million to $2 million annually.[61] These costs would cover market operations, settlement systems, compliance monitoring, and regular review and updates of the market parameters and constraints. Additional staff resources would likely be required to manage the increased complexity of dispatch and to maintain the technical systems supporting inertia price formation and settlement.

5.3.3 Market participant costs

Market participants providing inertia services would also face costs to participate in the spot market, which should be considered as part of an evaluation of the costs against estimated benefits. These participant costs would include upfront costs to develop bidding capabilities and interfaces with AEMO's systems, ongoing costs for market analysis, and compliance costs associated with meeting technical performance requirements. Understanding these costs further, would be an important consideration for an evaluation of a spot market approach. That said, it would likely not be unreasonable to expect that market participants would incur ongoing costs of $0.2 to $0.4 million each year.[62]

The total cost to implement and operate an inertia spot market over a 10-year period could therefore range from $20 to $50 million in present value terms,[63] accounting for both AEMO's costs and those faced by market participants. This estimate assumes 5 to 10 active market participants and applies a 7 per cent

[60] AEMO, NEM reform program post implementation review – fast frequency response, April 2024, table 1, p 11. This cost is associated with the FFR initiative delivery, which became effective from 9 October 2023 when the two new markets for 1-second raise and lower FCAS were introduced in the NEM. AEMO notes that this cost does not cover the costs incurred by participants associated with implementation of the initiative.

[61] As a benchmark, AEMO's operating expenditure for the 'NEM core' segment in 2023-24 was $169 million, which consists of $96 million for labour costs. The 'NEM core' segment includes operating the energy system to ensure power system security and reliability, operating the energy market including wholesale metering, settlements and prudential supervision, and near-term energy forecasting and planning. See: AEMO, Annual report – FY24, pp 37 and 38; available at https://aemo.com.au/-/media/files/about_aemo/annual-report/2024/annual-report-fy24-vfinal.pdf?la=en, accessed on 11 November 2024.

[62] The estimate covers assumed labour costs only.

[63] This lower bound is calculated by taking the lower bounds of the individual components (ie, $5 million, $1 million and $0.2 million of one-off implementation costs, annual operating costs and ongoing market participants' costs respectively) for 5 active market participants. The upper bound is calculated by taking the upper bounds of the individual components (ie, $10 million, $2 million and $0.4 million for the aforementioned costs) for 10 active market participants. Estimates are obtained over a 10-year period with a discount rate of 7 per cent.

discount rate. While significant, these costs should be evaluated against the potential market benefits that could be realised through co-optimisation of inertia with other system services.

As noted earlier, there are also some technical and practical limitations that could affect implementation costs. For example, the market systems would need to handle the binary nature of inertia provision, account for locational requirements during islanded conditions, and manage the interaction between inertia dispatch and system security constraints. These complexities may require more sophisticated technical solutions than initially estimated, potentially pushing costs toward the higher end of the ranges presented above. Regular review and enhancement of market systems would likely be needed as experience is gained with market operation.

5.4 Observations from our quantitative economic benefits analysis

Our quantification analysis has evaluated four potential sources of benefits from providing operational top-up and additional inertia services in the NEM. The analysis reveals several important insights about the likely magnitude and timing of these benefits.

5.4.1 Additional inertia services

Our analysis indicates that the benefits to the market from optimising FFR with additional inertia in the current market circumstances are likely to be relatively low. This reflects the significant quantity of inertia that remains available in the NEM through energy dispatch outcomes.

However, these benefits could increase over time as the power system continues to transition. The progressive exit of synchronous generation from the market will reduce the byproduct provision of inertia through energy dispatch. This reduction in system inertia, combined with growing demand for FFR services, is likely to put upward pressure on the costs of procuring 1-second FCAS. In these circumstances, there may be increasing value in being able to optimise the trade-off between additional inertia and FFR services depending on how the supply of FFR services evolves in line with increasing demand.

It is important to note that realising these future benefits depends critically on the technical feasibility of dynamically optimising the relationship between inertia and FFR in operational timeframes. While the theoretical relationship between these services is well understood, we understand that implementing this optimisation in practice requires sophisticated control systems and careful consideration of power system security requirements.

Our analysis indicates that the economic benefits resulting from alleviating RoCoF constraints in the system may have a wide range, from $2 to $355 per MWs depending on when and where low levels of operational inertia arises. Our analysis highlights the nature of uncertainty as to whether economic benefits might be realised in the future, since it is uncertain how often RoCoF-related constraints are expected to restrict dispatch of more efficient generation resources in the future.

5.4.2 Operational top-up inertia services

We find that the most significant potential benefit from introducing operational top-up inertia services arises from potentially avoiding the need for AEMO to issue directions to synchronous generators during periods of low operational inertia. These directions are already imposing substantial costs on the market (while acknowledging that our analysis encompasses historical directions for system strength and system security purposes specifically). Based on historical compensation costs for directed generators in South Australia, we estimate that procuring operational top-up inertia efficiently could deliver several million dollars in annual benefits by reducing reliance on directions.

However, it is important to recognise that the underlying cause of these directions often relates to insufficient inertia being available in specific network locations during certain operating conditions. This suggests that improved system planning and strategic placement of synchronous condensers may be a more cost-effective solution than relying on short-term price signals through a spot market. The locational nature of inertia requirements during islanded conditions makes it particularly challenging to address through market mechanisms alone.

With respect to avoiding contingency size changes, our analysis suggests a relatively wide range of benefits from $0.7 million and $7.2 million annually. The estimated benefit is sensitive to the assumption of how often contingency sizes are changed to address operational inertia shortfalls, and the increased system costs associated with constraining the output of large generating units to manage system security. While these benefits could potentially increase if larger contingencies emerge in the future (for example, from renewable energy zones or offshore wind), they remain small on its own compared to the potential costs of establishing and operating a spot market.

Looking ahead, while there are clear benefits from introducing operational top-up and additional inertia services in the NEM, our analysis suggests these benefits may not be large in the near term. That said, there is the potential for these benefits to be higher in the future as synchronous inertia from energy dispatch falls as a result of synchronous generators' retirement. Obtaining a better understanding of the costs of implementing and operating a spot market, while evaluating the likely future costs of 1-second raise FCAS as synchronous inertia capacity falls in the NEM, will help with evaluating the merits of pursuing a spot market for operational top-up and additional inertia services. Such an analysis will also assist with understanding when such a market mechanism should be contemplated in the NEM.

A1. Appendix – Methodology for estimating the economic benefits of operational top-up and additional inertia services

In section 5.1, we describe our methodologies for estimating the economic benefits that could arise from providing operational top-up and additional inertia services in the NEM. We focus on four key sources of potential benefits, ie:

- for operational top-up inertia:
  - economic benefits arising from avoiding contingency size reductions (*'contingency size change'* benefit);
  - economic benefits arising from reducing the need to direct generators to synchronise (*'directions reduction'* benefit);
- for additional inertia:
  - economic benefits arising from substituting between additional inertia and FFR (*'inertia – FFR optimisation'* benefit); and
  - economic benefits arising from alleviating RoCoF-induced constraints imposed on interconnector flows and energy generation ('*RoCoF constraints alleviation*' benefit).

In this appendix we describe the methodologies in greater detail for all benefit categories except for the '*RoCoF constraints alleviation*' benefit. The methodology for this benefit category is relatively simple and captured appropriately in section 5.1.2.

A1.1 Methodology to estimate the economic benefits of optimising fast frequency response and inertia

Our approach aims to estimate the potential economic benefits arising from co-optimising additional inertia and FFR (particularly 1-second raise FCAS). The approach is intended to provide an order-of-magnitude assessment of the benefits, without being dependent on any specific market design. It assumes that the technical capability exists to operationalise these trade-offs between additional inertia and 1-second raise FCAS.

Central to the approach is the analysis of the extent to which additional inertia could decrease the quantity of 1-second raise FCAS, subject to maintaining system security and unchanged contingency size. To this end, we derive the uncapped[64] 5-minute quantities of 1-second raise FCAS between 10 October 2023 and 9 October 2024 (ie, one full year of data since the commencement of the 1-second FCAS markets). Subsequently, our analysis centres around 're-allocating' the observed uncapped 1-second raise FCAS between inertia and 1-second raise FCAS, in a hypothetical scenario whereby additional inertia is available to substitute the need for 1-second raise FCAS. The re-allocation is undertaken from a least-cost perspective by considering the costs of providing additional inertia and 1-second raise FCAS.

To avoid confusion, within the scope of this analysis we will refer to the 'pre-optimised' 1-second raise FCAS (ie, the uncapped 1-second raise FCAS observed in the past and projected into the future) as the FFR requirements. We will refer to the 'post-optimised' 1-second raise FCAS as 1-second raise FCAS.

A step-by-step description of the methodology involves:

[64] The 1-second raise FCAS was capped during the first few months since its commencement on 9 October 2023. Using the capped quantities would not be appropriate for our analysis since we will scale the historical quantities up to project future FFR requirements. The AEMO's Electricity Data Model provides information (in table dispatchconstraints) that allows us to derive the uncapped 1-second raise FCAS quantities.

- step 1: develop cost functions for both inertia and 1-second raise FCAS
  - the cost assumptions for inertia are obtained from the estimates in table 3.1:
  - the cost assumptions for 1-second raise FCAS are calibrated by using actual bids data documented in the AEMO's Electricity Data Model;
- step 2: gather information about the trade-off relationship between additional inertia and 1-second raise FCAS;
- step 3: collect historical data on the 5-minute FFR requirements (ie, uncapped 1-second raise FCAS quantity) between 10 October 2023 and 9 October 2024, and project these quantities for the next ten years by applying a growth rate that is proportional to the decrease in synchronous inertia capacity over this time horizon;
- step 4: develop a simplified technology investment optimisation model to determine the least-cost combination of inertia and 1-second raise FCAS that would meet the FFR requirements derived in step 3;
- step 5: estimate the total cost of meeting FFR requirements (between 2024 and 2033) with and without allowing provision of incremental inertia; and
- step 6: quantify the impact of additional inertia on the total cost of meeting FFR needs (ie, the difference in costs obtained in the 'with inertia' and 'without inertia' scenarios in step 5).

If the cost of providing inertia is less than that of 1-second raise FCAS, the total cost of meeting FFR requirements in the 'with inertia' scenario will be less than that in the 'without inertia' scenario. The decrease in the total cost of meeting FFR requirements is the economic benefit of additional inertia arising from reducing the need for 1-second raise FCAS.

Below we set out the key details in the methodology.

Estimated cost curve of 1-second raise FCAS

A cost curve of 1-second raise FCAS is required to understand its cost relativity with inertia, which underpins the extent to which inertia could substitute 1-second raise FCAS on a cost basis. Fixed and variable costs of different types of inertia are estimated by applying approaches described in appendix A2.

To obtain a cost curve for 1-second raise FCAS, we examine bids data on a sample of days between May 2024 and August 2024, which is selected to capture a 'stable' period without capping imposed on the 1-second raise FCAS market.

Based on bid prices and quantities, a cost curve is constructed for each five-minute interval over the sampled days. We observe that the cost curves may vary from period to period, which may reflect the nature of varying opportunity costs across times of day and days.

As explained in section 5.1.1, historical bids by providers of 1-second raise FCAS may represent an upper end of variable costs. To alleviate potential concerns about an over-estimation of these costs from historical bid information, we have taking the lowest bid price (across the sample historical 5-minute data) for each quantity of FCAS to construct a cost curve for 1-second raise FCAS. We consider this approach is reasonable in obtaining a bids-derived cost curve that best represents the underlying variable costs of supplying each capacity of 1-second raise FCAS.

Regarding fixed cost, we explained in section 5.1.1 that it is highly challenging to estimate with certainty. This is because batteries are developed to provide a range of services (eg, energy and FCAS markets participation). Therefore it is unclear the extent to which capital costs would be attributable to a particular service only.

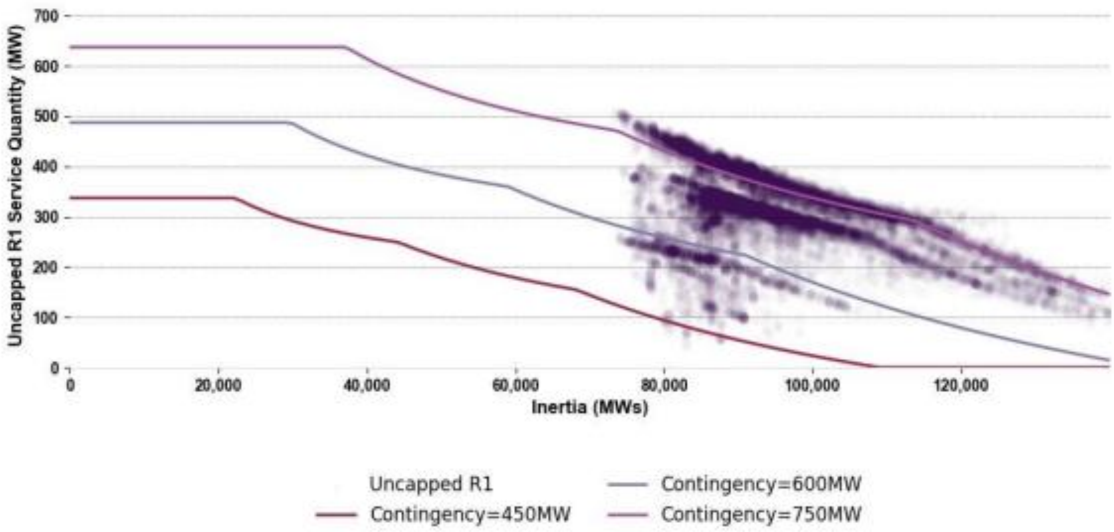
We assume 50 per cent of the capital cost of a battery would be attributed to 1-second raise FCAS.[65] This assumption underpins the results presented in section 5.2.1. The sensitivity results by applying alternative assumptions of fixed cost for 1-second raise FCAS are presented in appendix A3.

These estimated fixed and variable costs are applied in all years in the scenario in which FFR market value is assumed to increase. In the other scenario in which FFR market value is assumed to remain or decrease, the fixed and variable costs are assumed to decrease at a rate of eight per cent per annum. The decrease rate is derived from AEMO's projections of battery capital costs between 2024 and 2030. These projections are used in the Integrated System Planning 2024.

Trade-off relationship between additional inertia and 1-second raise FCAS

Figure A1.1 presents a trade-off relationship between inertia and 1-second raise FCAS that was studied by AEMO. We leverage this information to derive the trade-off relationship between inertia and 1-second raise FCAS (ie, the downward sloping of a curve). We take the midpoint contingency scenario (ie, 600 MW) in our analysis. The estimated trade-off rate is such that 1 MWs of inertia is equivalent to 0.004667 MW of 1-second raise FCAS.

Figure A1.1: Trade-off curve between inertia and 1-second raise FCAS



Source: AEMO, Frequency monitoring – quarter 2 2024, August 2024, pp 11 and 12.

A simplified technology investment optimisation model

The model inputs include fixed and variable costs of technologies providing inertia (described in greater detail in appendix A2), fixed cost and variable cost curve of 1-second raise FCAS, trade-off rate between inertia and 1-second raise FCAS, and five-minute traces of uncapped FFR requirements.

The traces of uncapped FFR requirements are assumed to increase over time in a proportionate rate to the decrease in synchronous inertia capacity in the NEM. Fixed and variable costs are assumed to either remain or decrease over time depending on which scenario of FFR market value the costs are applied to.

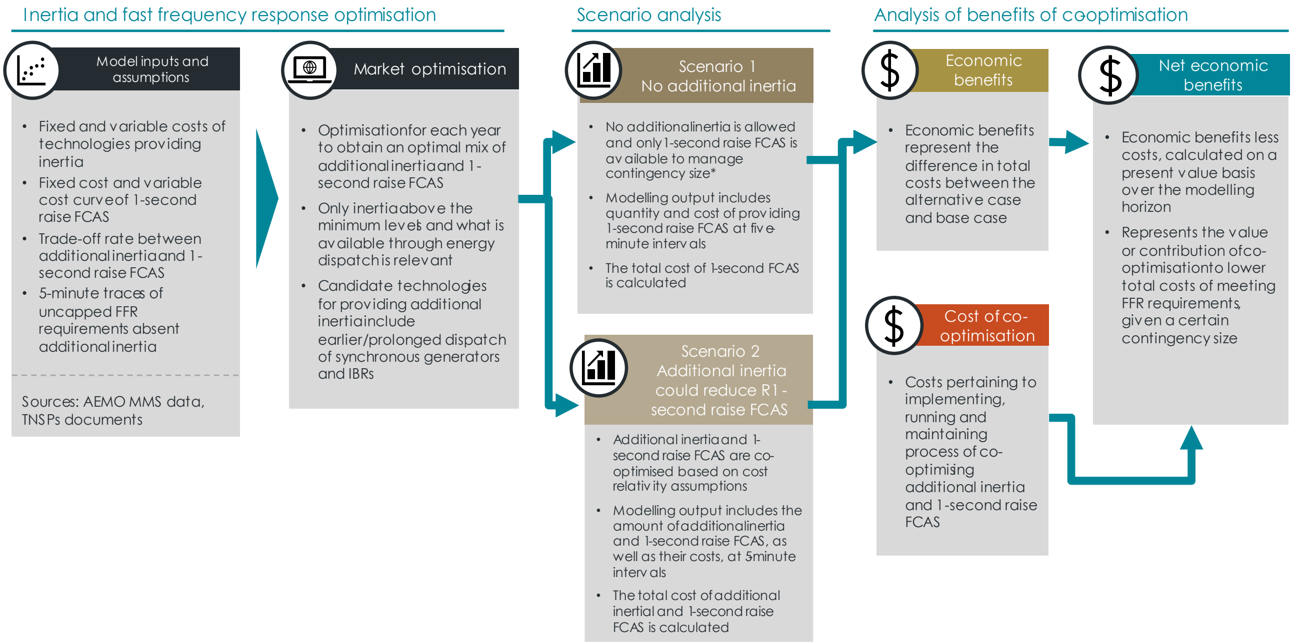
[65] Our analysis of public information and data indicates an absence of definitive estimate of this proportion. For the purpose of this analysis, we assume a 50 per cent proportion as a starting point to reflect to approximately split of BESS revenues between energy and FCAS markets on average. This assumption is tested with sensitivity analysis to inform our assessment.

The optimisation occurs over each year to determine the optimal mix of additional inertia and 1-second raise FCAS. Candidate technologies for providing additional inertia include earlier/prolonged dispatch of synchronous generators and IBRs.

The optimisation is rerun for each scenario and sensitivity case. Different optimal mix outcomes between additional inertia and 1-second raise FCAS are obtained, resulting in varying total costs of meeting FFR requirements across scenarios. The variability underpins the range of economic benefits presented in section 5.2.1 and appendix A3.

Figure A1.2 summarises the optimisation modelling steps from inputs / assumptions to economic benefits outcomes in a schematic diagram. The optimisation model is developed using Python programming language and uses Gurobi as its optimisation solver.

Figure A1.2: Modelling framework to estimate the economic benefits of optimising fast frequency response and inertia



A1.2 Methodology to estimate the economic benefits of avoiding contingency size changes

Our approach facilitates an order of magnitude assessment of the potential economic benefits arising from using additional inertia to avoid the needs to decrease contingency sizes during periods of low inertia in the power system. The analysis aims to identify historical instances where pre-dispatch inertia falls below the minimum levels, and contingency size was decreased to address the operational inertia shortfalls. Subsequently, economic benefit is calculated as the avoided costs of decreasing contingency size, offset by the incremental costs of providing operational top-up inertia (that prevents contingency size from being decreased and less efficient generation resources being called upon).

Overall, our approach involves three steps, ie:

- step 1 – calculate the avoided costs of decreasing contingency size, which includes:

    > identifying 5-minute intervals in financial year 2023-24 where output of the largest generating unit in a 5-minute interval was below its maximum capacity and the wholesale energy price in the corresponding region was not negative;[66]
    > assuming the periods identified above represent instances of contingency size decrease in 2023-24;
    > random-sampling from the identified periods a sub-sample of periods that represent instances of contingency size decreases due to operational inertia shortfalls – sub-sampling is undertaken by assuming a range of frequencies (eg, one, two, five and ten per cent);
    > for each 5-minute period in the sub-sample:
        - using wholesale energy prices as a proxy for the average cost of avoiding each MW of contingency size decreases in the system;
        - calculating avoided cost by multiplying the constrained capacity of the largest generating unit (ie, maximum capacity minus dispatched output) with the wholesale energy price of the period;
    > calculating total avoided costs for a whole year by summing avoided costs across all 5-minute periods in the sub-sample;
- step 2 – calculate the additional costs of providing operational top-up inertia (in order to avoid having to decrease contingency size), which includes:
    > assuming either synchronous generators (by earlier/prolonged dispatch) or IBRs would be available to provide the operational top-up inertia that could prevent contingency sizes from decreasing;
    > for each 5-minute period in a sub-sample:
        - calculating the amount of operational top-up inertia needed to prevent the contingency size of that period from decreasing (ie, the amount of incremental inertia is equivalent to the MWs equivalent of the constrained capacity of the largest generating unit, calculated using the H constants);
    > calculating the operational top-up inertia cost by multiplying the amount of operational top-up inertia with the unit cost estimates of inertia (as presented in Table 3.1);
- step 3 – estimate the economic benefit of operational top-up inertia by taking the total avoided cost of decreasing contingency sizes (in step 1) minus the incremental costs of providing operational top-up inertia (in step 2). Average economic benefits are calculated by averaging across cases of examined technologies (assumed in step 2).

We acknowledge several limitations in the available data and therefore our approach relies on key assumptions that can be tested through sensitivity analysis. Most notably, we cannot directly observe which historical periods of reduced contingency size were driven by operational inertia shortfalls versus other system conditions. Therefore, we test different assumed frequencies of inertia-driven contingency size reductions to understand how the potential benefits vary under different assumptions of frequency.

The final economic benefit calculation provides a range of potential values based on the sensitivity analysis around the assumed frequency of inertia-driven contingency size reductions. This approach allows us to understand the order of magnitude of potential benefits while acknowledging the uncertainty in some of the underlying assumptions. It also provides insights into which assumptions most significantly affect the estimated benefits, helping to identify areas where better data collection could improve future analysis.

A1.3 Methodology to estimate the economic benefits of avoiding directions to support system security

Our approach facilitates an order of magnitude assessment of the potential economic benefits arising from using operational top-up inertia to avoid directing synchronous generators online during periods of low system inertia, particularly in South Australia. We understand that this situation typically arises in islanded

[66] This is to exclude peridos when synchronous generators are running at minimum generation for economic reasons, as opposed to being decreased to address operational inertia shortfalls.

regions when operating synchronous generators are already at minimum generation levels and contingency sizes cannot be further reduced.

Our approach to estimating the potential benefit of avoiding directions involves two steps, namely:

- step 1 – calculate the avoided costs of directions, which includes:
  - identifying historical instances between April 2023 and March 2024 where synchronous gas generators in South Australia were directed to dispatch;[67]
  - analysing directions compensation payment and additional compensation of the identified directions;
  - calculating the range and average cost of each direction, which vary by the length of the direction and the generating unit being directed;
- step 2 – estimate the additional costs of providing operational top-up inertia for each direction (in order to avoid issuing directions), which includes:
  - assuming either synchronous generators (by earlier/prolonged dispatch) or IBRs would be available to provide the operational top-up inertia that could prevent directions from being issued;
  - for each of the identified directions in step 1:
    - calculating the amount of operational top-up inertia that is needed to avoid issuing directions (ie, the amount of operational top-up inertia is equivalent to the inertia provided by the directed unit);
    - calculating the operational top-up inertia cost by multiplying the amount of operational top-up inertia with the unit cost estimates of inertia (as presented in Table 3.1);
- step 3 – estimate the economic benefit of operational top-up inertia for each direction by taking the average avoided cost of direction (in step 1) minus the additional costs of providing operational top-up inertia (in step 2). Average economic benefits are calculated by averaging across cases of examined technologies (assumed in step 2).

The methodology leverages actual historical direction costs from South Australia, which provides concrete data about the costs of using directions to maintain system security during periods of low inertia. This gives us greater confidence in the avoided cost calculations. However, we note that the data contain historical directions issued for system strength and system security purposes (not inertia specifically).

The total avoided costs (and so benefits) associated with avoiding directions will be critically dependent on expectations of the need for directions in the future. Given the emergency nature of directions, we expect that the number of directions in any year are likely to be low, as alternative mechanisms or investments will be put in place to reduce the need for directions, given the costs involved.

[67] The period is chosen to reflect the most recent period with data availability regarding compensation costs.

A2. Appendix – Inputs and assumptions

In this appendix, we set out the key inputs and assumptions underlying our cost estimates for different technologies in providing inertia. The cost estimates are used as inputs to the assessment of the potential economic benefits of operational top-up and additional inertia services in the NEM.

A2.1 Estimation of incremental costs of providing inertia

This section sets out the inputs and assumptions underlying our summary, in table 3.1 above, of the costs of providing inertia by source. For each source, we have estimated the incremental costs of providing inertia on a per unit basis. In particular, we have estimated:

- $/MWs/hour variable costs; and
- $/MWs/year fixed costs.

We describe the relevant inputs and assumptions with examples of calculations for each of the following sources of inertia in turn:

- inertia from existing synchronised generation;
- inertia from flywheels added during the construction of a new synchronous condenser that is being built for another purpose, such as to provide system strength;
- inertia from new synchronous condensers (with a flywheel) built for the purpose of providing inertia services;
- inertia from repurposing a synchronous generator to operate as a synchronous condenser; and
- synthetic inertia from IBRs.

Inertia from existing synchronised generation

Section 3.2.1 describes how traditional synchronous generators provide inertia in the power system as a byproduct of generation. A synchronous generator provides the same level of inertia regardless of whether it is operating at its minimum stable output, at its maximum capacity, or anywhere in between (because the stored kinetic energy in its rotating mass is the same, as long as it is online).[68]

To estimate the *incremental* costs of providing inertia from synchronised generation, we have distinguished between three cases:

1. Where a synchronous generator is already online to provide energy, it provides inertia as a byproduct, and so the incremental cost of inertia services is zero.
2. Where a synchronous generator comes online earlier – or stays online later – than it otherwise would (ie, out of merit order dispatch), to provide inertia, then it incurs incremental variable operating and maintenance (O&M) costs and emissions costs associated with providing inertia. In this case, we assume that the generator would operate at its minimum stable output level.
3. Where a synchronous generator delays its retirement so that it remains available to provide inertia, then it incurs incremental fixed and variable operating O&M costs and emissions costs associated with providing inertia. In this case, we assume that the generator would operate at its minimum stable output level.

[68] We understand that some synchronous generators can operate in synchronous condenser mode – this is considered separately below (see inertia from repurposing a synchronous generator to operate as a synchronous condenser).

We have estimated the fixed O&M costs, variable O&M costs and emissions costs for each generator in the NEM by applying the formulae in Table A2.1.

Table A2.1: Estimation of synchronous generator incremental costs of inertia supply

	Fixed operating and maintenance costs ($/MWs/year)	Variable operating and maintenance costs ($/MWs/hour)	Emissions costs ($/MWs/hour)
Formula	$Min\ stable\ level\ (MW) * annual\ fixed\ O\&M\ cost\ (\$/MW) \,/\, inertia\ (MWs) = fixed\ cost\ of\ providing\ inertia\ (\$/MWs/year)$	$Min\ stable\ level\ (MW) * variable\ O\&M\ cost\ (\$/MWh) \,/\, inertia\ (MWs) = variable\ cost\ of\ providing\ inertia\ (\$/MWs/hour)$	$Min\ stable\ level\ (MW) * 2024\ emissions\ cost\ (\$/MWh) \,/\, inertia\ (MWs) = emissions\ cost\ of\ providing\ inertia\ (\$/MWs/hour)$
Source	Min stable level sourced from AEMO, *2024 ISP inputs and assumptions workbook*, 'GPG Min Stable Level' and 'Generation Limits' sheets. $Inertia\ (MWs) = Max\ capacity\ (MW) * H\ constant\ (seconds)$ Max capacity sourced from AEMO, *October 2024 NEM generation information*, 'Existing generation and new developments' sheet, column M ('nameplate capacity'). H constant sourced from AEMC generator information.		
	Annual fixed operating and maintenance costs ($/MW) sourced from AEMO, *2024 ISP Inputs and Assumptions Workbook*, 'Fixed OPEX' sheet.	Annual variable operating and maintenance costs ($/MWh) sourced from AEMO, *2024 ISP Inputs and Assumptions Workbook*, 'Variable OPEX' sheet.	$2024\ emissions\ cost\ (\$/MWh) = Emissions\ intensity\ (kg/MWh) * VER\ (\$/tonne)\ /1000$ Emissions intensity (kg/MWh) for each generator sourced from 2024 ISP Inputs and Assumptions Workbook, 'Emissions intensity' sheet. VER ($/tonne) sourced from AER, Valuing emissions reduction final guidance, May 2024, p 4. 2024 column used.
Black coal estimate	$6,300 - $9,200	$0.50 - $0.73	$6.43 - $8.97
Brown coal estimate	$26,000 - $29,000	$0.77 - $0.85	$13.14 - $15.83
Gas estimate[69]	$700 - $3,900	$0.30 - $1.10	$1.53 - $3.45

We note that hydro generators can also be used to provide synchronous inertia, but have not estimated those costs here, given the level of uncertainty.

The cost ranges presented in Table A2.1 above are the interquartile range of synchronous generator costs for each fuel type (ie, the range of costs for generators of that fuel type, excluding outliers).

[69] Cost estimates on a per MWs basis for gas generators exhibit significant variability due to different expected inertia constants of different plants.

Table 3.1 (in the main body of this report) presents the interquartile range of costs across all existing coal and gas synchronous generators, excluding outliers. For example, we assume that the shutdown of a brown coal plant for inertia purposes would not be contemplated, given the high cost.

Inertia from flywheels added during the construction of a new synchronous condenser

Fixed costs

Section 3.2.2 explains that synchronous condensers can be equipped with additional flywheels during construction, which can substantially increase their inertia contribution at relatively low incremental cost.

Synchronous condensers may be built in the NEM to provide system strength[70] - ie, for a purpose other than to provide inertia. In this case, the incremental costs of providing inertia would be the costs of adding a flywheel during construction of the synchronous condenser.

We have estimated the fixed costs of adding a flywheel in this case using the following assumptions for key parameters:

Table A2.2: Key parameter assumptions for synchronous condenser and flywheel cost estimates

Parameter	Value	Source
Discount rate	7 per cent	2024 ISP
Asset life of a synchronous condenser/flywheel	40 years	Transgrid, *System strength PADR NPV model core portfolios*, 'I2.1 Capex' sheet.
Capital cost of flywheel	$2 million	AEMO, *2024 ISP*, Appendix 7 – system security, p 18.
Flywheel size (inertia)	1000 MWs	Sources (eg, AEMO 2024 ISP, Transgrid system strength PADR) assume flywheel inertia between 1000MWs and 1500MWs. 1000 MWs assumed throughout this report.
Fixed operating and maintenance costs	1 per cent of capex	See eg, ElectraNet, System strength requirements in SA | RIT-T PSCR, November 2023, p 27.

We have applied these assumptions using the following steps:

- calculate annualised capital cost using assumed asset life of 40 years and discount rate of 7 per cent;
  - ie, annualised capital cost of flywheel = $\frac{\$2{,}000{,}000*0.07}{1-(1+0.07)^{-40}} = \$150{,}018$
- add annual fixed operating and maintenance costs, assumed to be 1 per cent of capital expenditure;
  - ie, annual fixed operating and maintenance costs = $0.01 * \$2{,}000{,}000 = \$20{,}000$
- total annualised cost = annualised capital cost plus annual fixed operating and maintenance cost;
  - ie, total annualised cost = $\$150{,}018 + \$20{,}000 = \$170{,}018$
- divide total annualised cost ($) by inertia of flywheel (1000MWs) to obtain cost estimate in $/MWs/year;

[70] See Powerlink, *Assessing system strength requirements in Queensland from December 2025*, PADR, November 2024, pp 17-20; and AER, *The efficient management of system strength framework*, AER draft guidance, October 2024, p 31.

- ie, per unit incremental cost = $\frac{\$170{,}018}{1{,}000MWs} = \$170/MWs/year$.

Variable costs

We understand that operating a synchronous condenser with or without a flywheel incurs some variable costs due to the need to draw electricity from the grid, and associated losses. Where a new synchronous condenser is used to provide system strength, then the variable costs associated with a synchronous condenser will be incurred regardless of whether a flywheel is added to provide additional inertia. We have not sought to quantify the incremental variable costs associated with running the synchronous condenser with a flywheel compared to running it without a flywheel, but we have assumed that they will be very low.

Inertia from new synchronous condensers (with a flywheel) built for the purpose of providing inertia services

Fixed costs

We have also considered the incremental costs of building a synchronous condenser for the purpose of providing inertia services – see Table A2.3.

The assumptions and methodology used to estimate fixed costs in this case are largely identical to the assumptions and methodology described above in relation to the fixed costs of adding a flywheel to a new synchronous condenser, except that the capital costs of a synchronous condenser are treated as part of the incremental costs.

We have used estimates from TNSP system strength RIT-T documents as indicative estimates of the capital costs of a synchronous condenser. These estimates vary and so we have taken an average of the costs calculated based on each TNSP estimate.

We have assumed that the synchronous condenser itself (without a flywheel) provides 1 MWs of inertia per MVA – ie, we have assumed that a 200MVA synchronous condenser would provide 200MWs of inertia.

Table A2.3: Estimating the fixed cost of providing inertia from a new synchronous condenser with a flywheel

	Estimate #1	Estimate #2	Estimate #3	Average
Syncon cost estimate	$98 million per 250 MVA syncon Transgrid, System strength PADR, June 2024, pp 5, 7. ($1,375m for fourteen 250 MVA syncons)	$135 million per 200 MVA syncon Powerlink, System strength PADR, November 2024, pp 72-73.	$80 million per 125 MVA syncon. ElectraNet, System strength PSCR, November 2023, p 21.	
Flywheel cost estimate	$2 million	$2 million	$2 million	
Annualised total capital cost (7 per cent discount rate, 40 year asset life)	$7,500,914	$10,276,252	$6,150,749	
Annual operating cost (1 per cent of capex)	$1,000,000	$1,370,000	$820,000	
Total annualised cost	$8,500,914	$11,646,252	$6,970,749	

	Estimate #1	Estimate #2	Estimate #3	Average
Inertia (MWs)	1,250 MWs (1,000 MWs flywheel plus 250 MWs syncon)	1,200 MWs (1,000 MWs flywheel plus 200 MWs syncon)	1,125 MWs (1,000 MWs flywheel plus 125 MWs syncon)	
Per unit cost ($/MWs/year)	$6,801	$9,705	$6,196	**$7,567**

Variable costs

We have estimated the variable costs of providing inertia through a synchronous condenser using the parameters and assumptions set out in the table below.

Table A2.4: Key parameter assumptions used to estimate variable costs of providing inertia through a synchronous condenser built for inertia

Parameter	Value	Source
Losses and energy consumption as a percentage of synchronous condenser rating	1.5 per cent	Digsilent, *Repurposing existing generators as synchronous condensers*, Report on technical requirements for ARENA, June 2023, p iv.
Average electricity price	$150/MWh	AER website, available at: <https://www.aer.gov.au/industry/wholesale/charts>.

Table A2.5 sets out how we have applied these assumptions to calculate indicative variable costs based on the three synchronous condenser sizes considered in Table A2.4 above.

Table A2.5: Estimating the variable cost of providing inertia from a new synchronous condenser with a flywheel

	125 MVA syncon	200 MVA syncon	250 MVA syncon
Energy consumption and losses	$0.015 * 125 = 1.88MW$	$0.015 * 200 = 3.00MW$	$0.015 * 250 = 3.75MW$
Cost (energy consumption multiplied by energy price)	$281/hour	$450/hour	$563/hour
Inertia (assuming inertia constant of 1 second for the syncon as above, plus a 1000MWs flywheel)	1,125 MWs	1,200 MWs	1,250 MWs
Variable cost of inertia ($/MWs/hour)	$0.25/MWs/hour	$0.38/MWs/hour	$0.45/MWs/hour

Inertia from repurposing a synchronous generator to operate as a synchronous condenser

Fixed costs

We understand from our review of a 2023 report by Digsilent, commissioned by ARENA,[71] that:

- the cost of repurposing a gas or hydro generator into a synchronous condenser is lower than the cost of building a new synchronous condenser, in particular:
- the cost of repurposing a gas generator into a synchronous condenser may be approximately 60 per cent of the cost of building a new synchronous condenser; and
- the cost of repurposing a hydro generator are low relative to the cost of building a new synchronous condenser (we have assumed 'low' to be 20 per cent as an indicative estimate);
- the cost of repurposing generators into synchronous condensers are uncertain at this stage, and likely to vary from generator to generator; and
- the cost of retrofitting a flywheel to an existing plant is likely to be significantly higher than the cost of adding a flywheel during the construction of a new plant (we have assumed three times higher, as an indicative estimate).[72]

Table A2.6 sets out how we have applied this understanding to estimate the costs of providing inertia from repurposed generators.

Given the level of variability regarding the costs of this technology type, the estimates we have obtained should be treated as indicative, 'order of magnitude' estimates only.

Table A2.6: Estimating the costs of providing inertia from a repurposed synchronous generator operating as a synchronous condenser with a flywheel

	Gas	Hydro
Assumed cost of repurposing generator relative to cost of new syncon (per MVA)	60 per cent	20 per cent
Repurposing cost estimate[73]	$48 million - $81 million (ie, 60 per cent multiplied by cost estimates for a new syncon (see Table A2.2))	$16 million - $27 million (ie, 25 per cent multiplied by cost estimates for a new syncon (see Table A2.2))
Retrofitting flywheel cost estimate[74]	$6 million	$6 million
Average per unit cost ($/MWs/year)	$4,883	$1,914

[71] Digsilent, *Repurposing existing generators as synchronous condensers*, Report on technical requirements for ARENA, June 2023.

[72] See also AEMO, *2023 Inertia report*, December 2023, p 4, footnote 2.

[73] See Table A2.2 for the source of the capital cost estimates for new synchronous condensers.

[74] These estimates apply our indicative assumption that retrofitting a flywheel costs three times as much as the $2 million capital cost of adding a flywheel to a new synchronous condenser (see Table A2.2).

Variable costs

The variable cost in this case is assumed to be identical to the variable cost of providing inertia from a newly built synchronous condenser with flywheel.

Synthetic inertia from IBRs

Fixed costs

We have assumed that between zero per cent (lower bound) and five per cent (upper bound) of the capital costs of a one-hour BESS represent the incremental fixed costs of using the BESS to provide inertia.

At the lower bound, the incremental fixed costs of inertia from BESSs are zero. This reflects that many BESS operators may incur all necessary capital (including software) costs that would enable the BESS to provide inertia regardless of whether the BESS is used to provide inertia. This includes a grid-forming inverter, which may be used for system strength or another purpose.

We have used the following assumptions to estimate the fixed costs at the upper bound – see Table A2.7.

Table A2.7: Key parameter assumptions used to estimate upper bound for fixed costs of synthetic inertia

Parameter	Value	Source
Total capital cost of 1 hour BESS	\$927,000/MW in 2024 \$561,000/MW in 2030 \$436,000/MW in 2036	CSIRO 2023/24 GenCost Report, Appx Table B4. (values converted from \$/kW to \$/MW)
Maximum proportion of capital cost that could be incurred for the purpose of providing inertia (ie, incremental capital cost)	5 per cent	Transgrid has estimated, based on discussions with stakeholders, that the cost of upgrading to a grid-forming inverter may be approximately 5 per cent of BESS capital cost – see: Transgrid, *Meeting system strength requirements in NSW*, *PADR*, June 2024, p 68.
Annual incremental fixed operating and maintenance costs.	1 per cent of incremental capital costs.	HoustonKemp assumption.
BESS inertia constant	6 seconds (ie, for every MW of capacity, the battery can provide 6 MWs of inertia)	AEMC assumption.
BESS asset life	20 years	HoustonKemp assumption.

We have applied these assumptions using the following steps:

- calculate annualised incremental capital cost using assumed asset life of 20 years and discount rate of 7 per cent;
  - ie, for 2024, annualised incremental capital cost of BESS= $\frac{0.05*\$927{,}000*0.07}{1-(1+0.07)^{-20}} = \$4{,}375/\mathrm{MW}$
- add annual incremental fixed operating and maintenance costs, assumed to be 1 per cent of incremental capex;

    - ie, for 2024, annual incremental fixed operating and maintenance costs = $0.01 * 0.05 * \$927{,}000 = \$464/MW$

- total annual incremental cost = annualised incremental capital cost plus annual incremental fixed operating and maintenance cost
    - ie, for 2024, total annual incremental cost = $\$4{,}375 + \$464 = \$4{,}839/MW$
- divide total annual incremental cost by inertia constant to obtain cost estimate in $/MWs/year:
    - ie, per unit incremental fixed cost = $\frac{\$4{,}839/\text{MW}}{6\ seconds} = \$806/MWs/year$
- repeat each step for different capital costs based on the year (recognising that BESS capital costs are projected to fall through time).

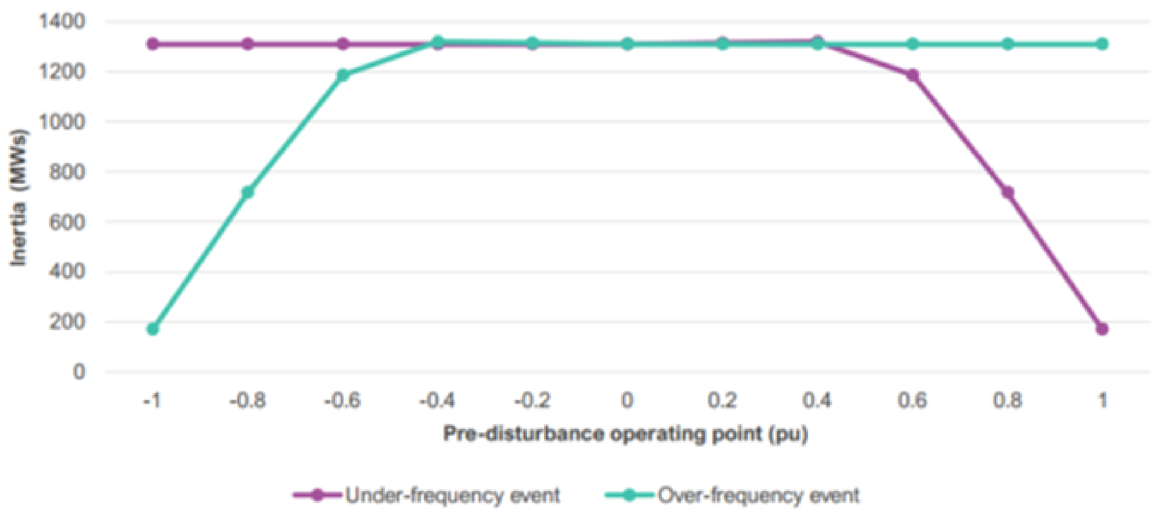
Variable costs

We understand that grid-forming BESS can provide a certain amount of inertia when connected to the network, irrespective of operating status (ie, charging, discharging or idle).

The amount of inertia provided by a BESS is a function of its operating point (defined as the proportion of operating power to maximum power). Figure A2.1 illustrates the trade-off between a BESS' operating point and the amount of inertia it can provide at any point in time. We note that the amount of inertia shown on the chart is specific to a grid-forming BESS in large contingency.

For instance, the trade-off curve suggests that when a grid-forming BESS is discharging (or charging) at 40 per cent of its maximum power, the BESS is able to provide inertia at its maximum.

Figure A2.1: Relationship between pre disturbance operating point and inertia for GFM BESS



Source: AEMO, Quantifying synthetic inertia of a grid-forming BESS – technical note, September 2024.

Drawing on the understanding of the technical trade-off between providing inertia (by restricting operating power) and arbitraging in the energy market, we understand that the most material contributor of variable cost for BESS to provide inertia is the forgone energy revenue due to the BESS' power being restricted in order to ensure a certain amount of inertia is provided at any point in time.[75]

[75] We understand that the cost of energy used for providing inertia is relatively small. We do not estimate this component in the variable cost estimation.

It follows that the methodology for estimating the variable cost of BESS in providing inertia revolves around estimating the foregone energy revenue for a BESS in order to provide inertia. In particular, we apply the following formula to estimate the variable cost of BESS in providing inertia, ie:

$$Variable\ cost\ of\ inertia\ =\ lost\ revenue\ /\ amount\ of\ inertia\ provided$$

We estimate lost revenue and amount of inertia provided by applying a simplified battery optimisation modelling framework. This approach allows us to observe the revenue-maximising operation of a 30 MW BESS in two cases, ie:

- ‘without inertia’ – a case in which the BESS’ power is not restricted and no inertia is assumed to be provided; and
- ‘with inertia’ – a case in which the BESS’ power is restricted to 90 per cent of its maximum power in order to provide a certain amount of inertia at any point in time.

In either case, the examined BESS will operate to maximise its revenue subject to its power limit (among other usual BESS constraints such as round-trip efficiency and storage capacity). The reduction in the BESS’ total revenue in the ‘with inertia’ case, compared to the ‘without inertia’ case, is the lost revenue that is attributable to inertia provision.

We undertake the optimisation modelling by taking into account wholesale energy prices in financial year 2023-24. Therefore, the lost revenue estimated is limited to that in the energy market. We consider this provides a lower bound for the variable cost of providing inertia, given that BESS may also forego revenue in FCAS markets in order to provide inertia.

To estimate the amount of inertia provided in the ‘with inertia’ case, we refer to the trade-off curve presented in Figure A2.1. In particular, we construct a linear function that best fits the downward-sloping segment of the curve. To generalise the fitted function, we convert the y-axis to proportion of maximum inertia (as opposed to inertia level). The generalised function of the relationship between inertia and operating power is as follows:

$$Proportion\ of\ maximum\ inertia\ =\ 1.6 - 1.4\ *\ proportion\ of\ maximum\ power$$

For simplicity, we have also linearised the function as opposed to using a step-wise linear function.

Using this generalised function, we can estimate the amount of inertia provided at each 5-minute interval in the alternative case by reference to the power at which the BESS is charging or discharging at that 5-minute interval.

The variable cost of inertia is calculated as the ratio of lost revenue to the amount of inertia provided over a period (in this case, in financial year 2023-24). This is the estimated variable cost of $0.44/MWs/hour set out in table 3.1 (in the main body of this report).

Key assumptions underlying the methodology are that:

- the BESS under consideration is of maximum power 30 MW;
- our approach does not capture forgone revenue (if any) of BESS in FCAS markets as a consequence of providing inertia;
- our approach does not capture foregone revenue in contractual arrangements by BESS;
- the methodology assumes perfect foresight with respect to wholesale energy prices, and that a BESS would trade optimally to maximise trading revenue. Efficiency cycle is assumed to be 85 per cent;
- the choice of 90 per cent capped power in the alternative case is illustrative. However, we note that the more restrictively the power is capped, the higher the lost revenue and therefore higher variable cost of providing inertia by IBRs; and

- the wholesale energy prices used in this analysis are from financial year 2023-24 to reflect the most updated whole-year price traces. Should a different wholesale energy price traces are considered, the estimated lost revenue may vary due to different price patterns across years.

A2.2 Synchronous condenser investment in the NEM

Section 2.3 explains that the upcoming decline in inertia capacity levels in the NEM as synchronous generation falls corresponds with a period of expected investments to meet system strength obligations, primarily by transmission network service providers (TNSPs), which can be adapted to also provide inertia at a low incremental fixed cost.

The analysis considers the prospect of synchronous condenser investment for system strength purposes as set out in recent RIT-T documents by TNSPs, noting that TNSPs may ultimately use alternative technologies to meet system strength obligations.

Table A2.8 sets out in more detail how we have constructed high and low scenarios of synchronous condenser investment. We also consider, in section 2.3, a scenario where no synchronous condensers are procured despite current TNSP expectations.

Table A2.8: Synchronous condensers included in high and low scenarios

Source	Available information	High scenario	Low scenario
Transgrid (New South Wales)	Preferred option at the PADR stage includes fourteen synchronous condensers by 2032/33, with a further 12 likely required by 2044/45 (the further 12 are not included in either of our scenarios). Option 3 is the credible option with the fewest synchronous condensers (10 by 2032/33). All credible options include a range of other technologies alongside syncons and will be considered further. Indicative timing of investment on page 45 of Transgrid PADR.[76]	14 * 250 MVA synchronous condensers: • 8 in 2029; • 2 in 2030; • 3 in 2031; and • 1 in 2032.	10 * 250 MVA synchronous condensers: • 5 in 2029; • 2 in 2030; • 3 in 2031; and • 1 in 2032.
Central West Orana REZ (New South Wales)	Seven 250MVA synchronous condensers expected in 2028 – based on AEMO's 2023 inertia report and August 2024 transmission augmentation information page, and Transgrid's PADR.[77]	7 * 250 MVA synchronous condensers in 2028	2 * 250MVA synchronous condensers in 2028.[78]
Powerlink (Queensland)	Top-ranked option at PADR stage includes nine 200MVA synchronous condensers to meet minimum fault level requirements. Option 3, with five synchronous condensers and four clutched gas turbines, may become preferred if the gas turbines become committed or anticipated. BESS expected to meet efficient (above minimum) levels, subject to further investigations. Option 4 is the credible option with the fewest synchronous condensers (four). All credible options include a range of other technologies alongside syncons that we have not explicitly included in our analysis, and the	9 * 200 MVA synchronous condensers: • 3 in 2029; • 4 in 2030; • 1 in 2033; and • 1 in 2034.	4 * 200 MVA synchronous condensers: • 0 in 2029; • 2 in 2030; • 1 in 2033; and • 1 in 2034.

[76] Transgrid, *Meeting system strength requirements in NSW*, PADR, June 2024, Table 5.1 and Table 5.5, pp 45, 51.

[77] See AEMO, *2023 Inertia report*, December 2023, p 11; Transgrid, *Meeting system strength requirements in NSW*, PADR, June 2024, p 30; and AEMO, *NEM transmission augmentation information August 2024*, 'Transmission augmentations' sheet, row 16.

[78] Two syncons is an assumption chosen to reflect a hypothetical case where fewer syncons required or available, and is repeated for Victoria and South Australia below.

	extent to which BESS can address minimum fault level requirements will be considered further. Indicative timing of investment on page 19 and 20 of Powerlink PADR.[79]		
AEMO (Victoria)	PSCR indicates that seven synchronous condensers or equivalent would be required to meet minimum fault level requirements, available from early 2028, and a further three to meet the efficient level of system strength from 2030 (these further three are not included in either scenario).[80] Non-network options are to be investigated.	7 synchronous condensers (6* 250 MVA and 1*125 MVA) in 2030.	2 * 250 MVA synchronous condensers in 2030.
ElectraNet (South Australia)	ElectraNet commissioned four synchronous condensers with flywheels in 2021.[81] PSCR indicates that five synchronous condensers or equivalent would be required to meet minimum fault level requirements, three in 2025/26 and two in 2028/29.[82] Non-network options are to be investigated.	4 existing 125 MVA syncons, plus: 5* 125 MVA synchronous condensers • 3 in 2028; and • 2 in 2029.	4 existing 125 MVA syncons, plus: 2 * 125 MVA synchronous condensers: • 1 in 2028; and • 1 in 2029.

We explain in section 2.3 our assumption that a 1000 MWs flywheel would be added to any newly built synchronous condenser.[83]

[79] Powerlink, *Assessing system strength requirements in Queensland from December 2025*, PADR, Figure 3.1 and Figure 3.2, pp 17-20.

[80] AEMO Victorian Planning, *Victorian System Strength Requirement*, PSCR, July 2023, pp 17-19.

[81] ElectraNet, *System Strength Requirements in SA*, PSCR, November 2023, p 11.

[82] ElectraNet, *System Strength Requirements in SA*, PSCR, November 2023, p 21.

[83] See Powerlink, *Assessing system strength requirements in Queensland from December 2025*, PADR, November 2024, p 58; Transgrid, *Meeting system strength requirements in NSW*, PADR, June 2024, p 30; and AER, *The efficient management of system strength framework*, AER draft guidance, October 2024, p 31.

A3. Appendix – Sensitivity analysis of the economic benefits of co-optimising additional inertia and 1-second raise FCAS

In section 5.2.1 we presented the economic benefits arising from co-optimising additional inertia and 1-second raise FCAS in order to meet FFR requirements. These results reflect an assumption that 50 per cent of battery capital costs are attributed to 1-second raise FCAS.

In this appendix we present the results of the sensitivity analysis in which alternative assumptions of 1-second raise FCAS fixed costs. The figures in this appendix presents economic benefits corresponding to the following assumed proportion of battery capital costs attributable to 1-second raise FCAS, ie:

- 70 per cent;
- 20 per cent; and
- five per cent.

Our sensitivity analysis indicates that the potential economic benefits arising from co-optimising additional inertia and 1-second raise FCAS are relatively robust to the assumptions around fixed cost of 1-second raise FCAS.

We set out a number of key detailed dynamics below.

First, economic benefits would be higher when the fixed cost of 1-second raise FCAS is higher. This reflects the fact that inertia would become increasingly competitive as the cost of 1-second raise FCAS increases. Therefore, there is greater opportunity for additional inertia to substitute 1-second raise FCAS and reduce the total cost of meeting FFR requirements.

Second, when fixed cost of 1-second raise FCAS is assumed to be five per cent of battery capital cost, it is equal to the fixed cost assumed for inertia. This implies that the results in this sensitivity case (Figure A3.3) demonstrates the extent to which additional inertia may be competitive with 1-second raise FCAS based on variable cost relativity only.

The results demonstrate that the economic benefits are potential immaterial when the variable cost of inertia is approximately $0.84 /MWs/hour (assuming the current FFR market value remains or decreases over time). If the current FFR market value is assumed to increase over time, the economic benefits would increase to approximately $6 million in 2033 (keeping the high variable cost assumption at $0.84/MWs/hour for inertia).

Overall, the assessment highlights the impact of assumptions around FFR market value evolution and cost relativity on the realised economic benefits arising from co-optimising additional inertia and 1-second raise FCAS.

Figure A3.1: Estimates of '*inertia – FFR optimisation*' benefits – fixed cost of 1-second raise FCAS assumed to be 70 per cent of IBRs capital cost

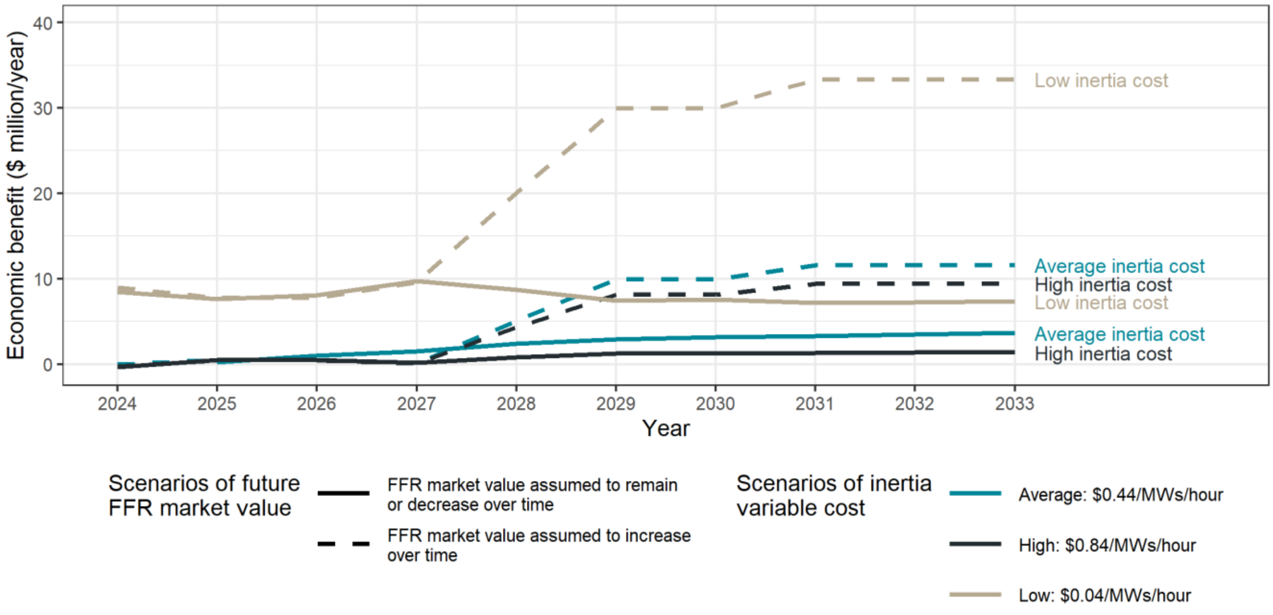


Figure A3.2: Estimates of '*inertia – FFR optimisation*' benefits – fixed cost of 1-second raise FCAS assumed to be 20 per cent of IBRs capital cost

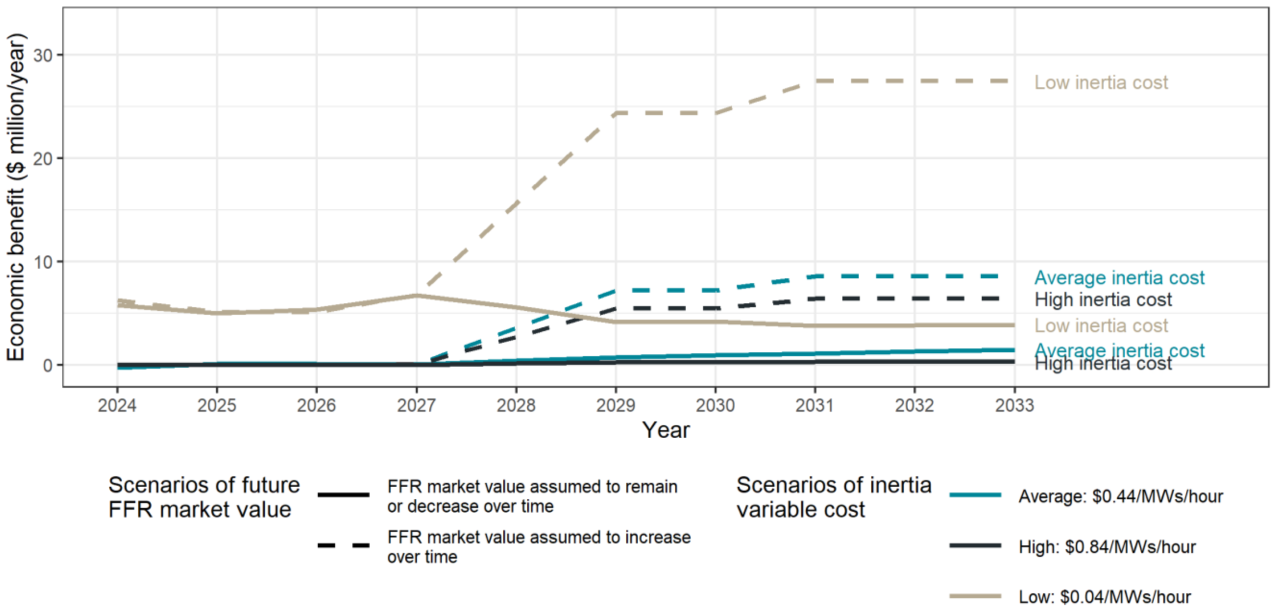
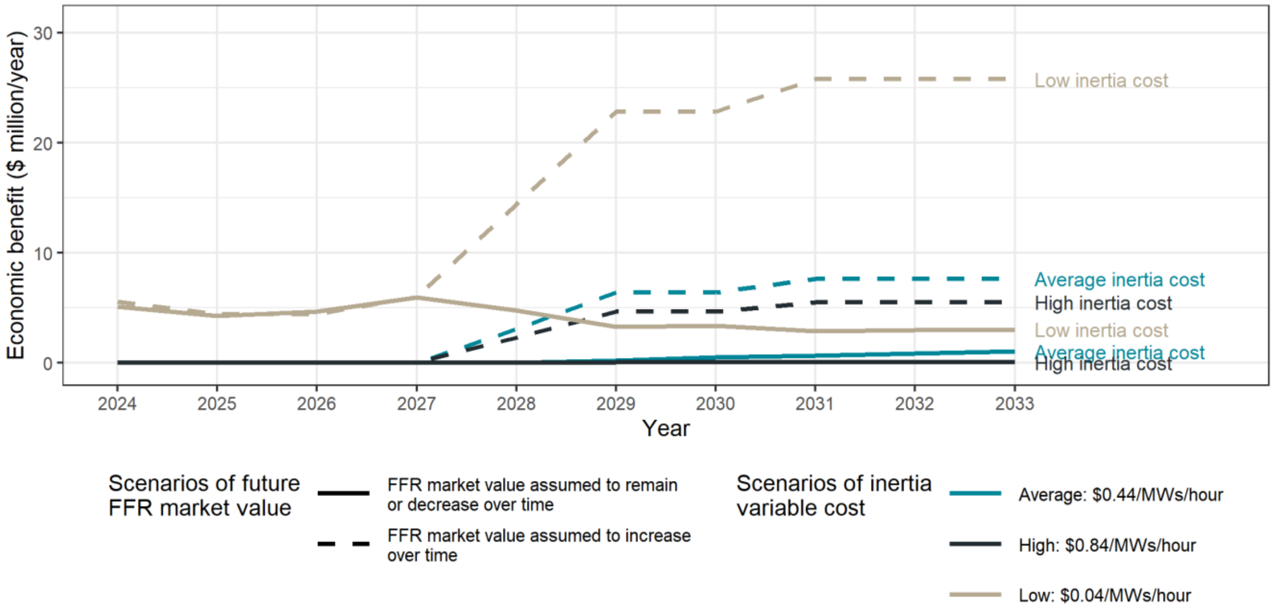


Figure A3.3: Estimates of '*inertia – FFR optimisation*' benefits – fixed cost of 1-second raise FCAS assumed to be five per cent of IBRs capital cost



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