Australian Energy Market Commission

DIRECTIONS PAPER

System Security Market Frameworks Review

23 March 2017

REVIEW

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About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Executive Summary

In this directions paper, the Australian Energy Market Commission (AEMC or Commission) presents its proposed approaches to addressing the two key systems security issues identified in its interim report published in December 2016: the management of frequency and of system strength in a power system with reduced levels of synchronous generation. The paper builds on the interim report, which explored the challenges associated with frequency control and set out a range of potential mechanisms for procuring new frequency management services.

The widespread deployment of new, non-synchronous generating technologies, such as wind farms and solar panels, is having major impacts on the operation of the power system. The AEMC is undertaking the System Security Market Frameworks Review to consider, develop and implement changes to the market rules to allow the continued uptake of these new forms of generation while maintaining the security of the system.

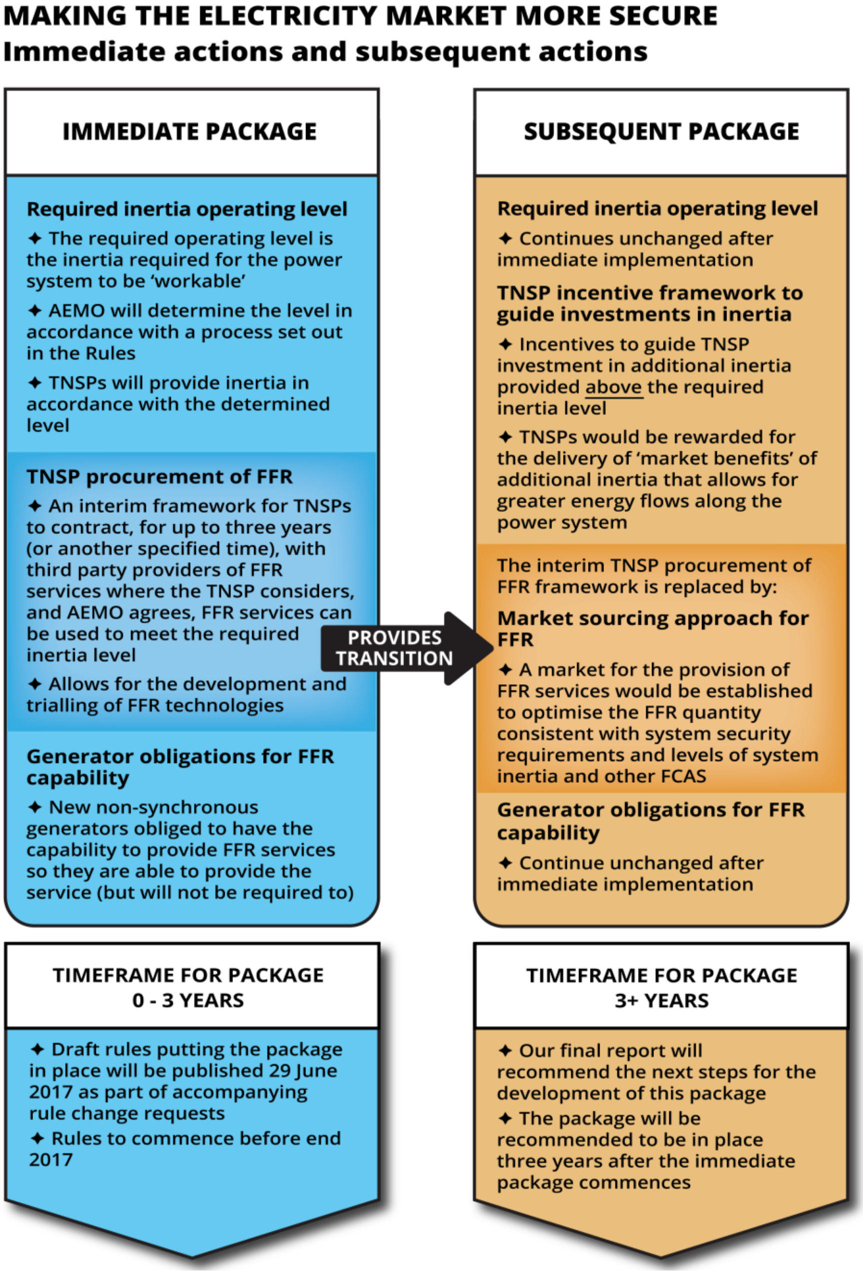
The review is drawing upon work being undertaken by the Australian Energy Market Operator (AEMO), as part of its Future Power System Security (FPSS) Program to identify and prioritise current and future challenges to maintaining system security. The review is also being conducted in parallel with the assessment of a number of rule change requests submitted by AGL and the South Australian Government relating to frequency control and system strength.

The focus of the review, and the rule changes, on these two issues is consistent with AEMO's prioritisation of the emerging challenges. However, further issues are already being identified, both by AEMO and by stakeholders more broadly, for future consideration. The Commission intends to give consideration as to how this broader work program will be structured and progressed as part of this review.

This paper assesses the identified frequency management options and distils them into two staged packages for further stakeholder feedback. It also provides a more detailed discussion of the issues associated with system strength than was contained in the interim report, and presents a proposed approach for consultation in this regard.

Approach to frequency control

The Commission's proposed approach to addressing frequency control consists of two packages of complementary measures that would be implemented in a staged manner: an immediate package and a subsequent package.



The immediate package represents a practical approach that can be adopted relatively quickly and which will provide a high degree of confidence that the system can continue to be operated in a secure manner. It consists of the following measures:

- *Required inertia operating level* - A requirement on Transmission Network Service Providers (TNSPs) to provide and maintain a defined operating level of inertia at all times. The required operating levels of inertia would be determined through a prescribed process conducted by AEMO, representing a workable level of inertia that would satisfy a range of, but not all, system conditions.

- *TNSP procurement of Fast Frequency Response* – As an interim measure, TNSPs would be allowed to contract with third party providers of Fast Frequency Response (FFR) services where the TNSP considers, and AEMO agrees, that an FFR service can be used to meet the required operating inertia level. The period of time during which contracts could be entered into would be limited to three years in order to provide a means for the development and trialling of FFR technologies.

- *Generator obligations for FFR capability* - An obligation on new non-synchronous generators to have the capability to provide FFR services. Generators would not be mandated to provide the service but would be required to install the capability for providing the service at the time of construction. The exact specification of the capability of the FFR service would likely depend upon the type of technology. An obligation of this nature would increase the level of FFR available in the system and would provide a foundation to establish a competitive market for FFR services.

The Commission is also proposing that two additional mechanisms should be subsequently implemented to enhance the immediate package. These two mechanisms would aim to improve the overall effectiveness and efficiency with which inertia and FFR services are procured in the long term and are as follows:

- *TNSP incentive framework to guide investments in inertia* - For additional inertia provided by the TNSP above the required operating level, an incentive framework would be developed to guide the inertia provided towards the most efficient level. Under the incentive framework, TNSPs would be rewarded for the delivery of market benefits from a project to provide additional inertia that allowed for greater power transfer capability in the network.
- *Market sourcing approach for FFR* - A market for the provision of FFR services would be established to optimise the FFR quantity consistent with system security requirements and levels of system inertia and other Frequency Control Ancillary Services (FCAS).

Both of these measures are likely to require considerable work to develop and implement. More importantly, the fledgling state of FFR technologies and the current small number of potential providers of FFR services means that it would be premature to define FFR services and seek to procure these through a market sourcing approach at this time.

TNSP contracts would provide a means of funding for the development of FFR services and would provide a basis for AEMO to develop specifications in relation to the service. The form and characteristics of the contracts would be determined in consultation with the FFR provider. However, AEMO would necessarily be involved in defining the conditions under which the service is enabled and utilised. This should allow for a more efficient transition to a market sourcing approach for the provision of FFR services in the longer term. The Commission understands that AEMO and ARENA are currently coordinating the identification of proof-of-concept projects to trial FFR services.[1]

1 COAG Energy Council, Meeting Communique, 17 February 2017, p. 1.

The current early stage of FFR technologies also presents a risk that incentivising TNSPs to seek market benefits opportunities might "lock-in" the provision of inertia from network investment over the long term. Consequently, the Commission considers it appropriate that the subsequent package is developed and implemented over the medium term, which might represent a period of three or more years.

In developing this staged approach, the Commission sought to strike a balance between addressing immediate issues related to the management of power system security and developing an efficient and effective framework to address such issues in the medium to longer term. Not only does this approach provide for immediate, practical solutions to key security issues but provides information to market participants that can support investment decisions and signals the proposed transition to markets for evolving technologies that can provide frequency services.

The two-stage packages address the issues identified in the interim report

In the interim report, the Commission identified three key factors that influence the ability to maintain control of power system frequency following a contingency event, such as the loss of a large generator, load or transmission line:

1. The initial rate of change of frequency (RoCoF), which is influenced by the size of the contingency and the level of system inertia.

2. The capability to restore the balance between supply and demand, and therefore stabilise the frequency, through the use of frequency response services.

3. The ability of generators and loads to withstand or “ride-through” the change in frequency.

Historically, inertia has been plentiful in the National Electricity Market (NEM), being provided as a consequence of having spinning generators synchronised to the frequency of the system. However, non-synchronous generators have low or no physical inertia and are, therefore, currently limited in their ability to dampen rapid changes in frequency.

As these new generating technologies achieve greater levels of penetration, a higher level of RoCoF will be experienced for a given contingency event, and there will be less time available to arrest the increase or decrease in frequency before it moves outside of permitted operating bands.

Consequently, in the interim report, the Commission set out its preliminary view that frequency control in the NEM would be enhanced by the introduction of both:

- a mechanism to obtain inertia, which would reduce the RoCoF and extend the time available to restore the frequency; and

- a fast frequency response (FFR) service. This would act to arrest the frequency change more quickly than the current fastest acting contingency frequency control ancillary service (FCAS), which has a response time of up to six seconds.

To some extent, these services would represent substitutes for each other: more inertia would permit a slower response, and a faster response would allow for less inertia. However, even the fastest frequency response technologies involve a time delay to measure the initial change in frequency and then activate the response. While this delay may only be in the order of hundreds of milliseconds, it does mean that there is a minimum level of inertia that cannot be replaced by FFR.

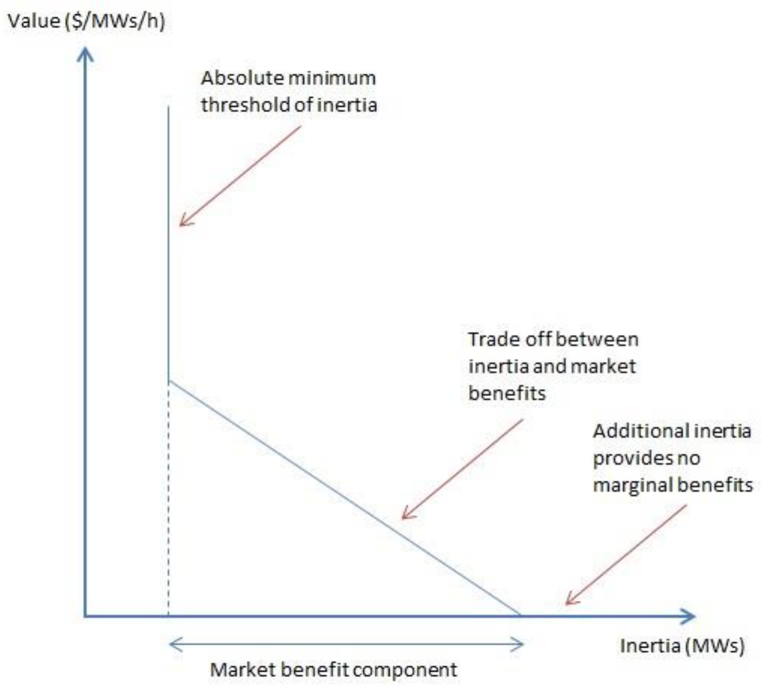
The level of inertia that is required to maintain the RoCoF to a given limit can be divided into two components:

1. **Minimum system threshold** – The absolute minimum level of inertia that is required to maintain the secure operation of the system. The absolute minimum level represents a lower bound on the level of inertia that is required to feasibly operate the system. Operating at this minimum level may require load shedding but would be sufficient to operate the islanded system to avoid a system black condition. This minimum level might not permit any interconnector flow, or limited flows, prior to separation.

2. **Market benefits** – Additional inertia above the minimum threshold would allow additional interconnector flows, improve reliability, and lower the overall cost of energy provision by alleviating constraints on the system.

The split between these two components is illustrated in figure 1, which shows a theoretical demand curve for inertia.

Figure 1 Value of inertia and the amount of inertia provided



The vertical line on the left represents the absolute minimum system threshold of inertia. This vertical line is a lower bound on the level of inertia that could feasibly be required in order to operate the system within the permitted operating bounds.

Beyond this level, the sloped line represents the trade-off that exists between the costs of supplying more inertia and other options for managing system security, such as constraining the system or obtaining FFR services. A continuation of the line shows that any additional inertia supplied to the market has no effect in further alleviating constraints on the system and so provides no additional benefit for either maintaining system security, improving reliability, or lowering the overall cost of energy production.

The immediate package introduces mechanisms to allow the procurement of both inertia and FFR, with the subsequent package giving effect to more sophisticated approaches to trading off the costs of these services against the costs that would arise from constraining generator dispatch in their absence.

As noted in the interim report, the Commission is continuing to give further consideration to both the appropriateness of the current generator performance standards relating to RoCoF withstand capability and whether it is necessary for work to be undertaken to better understand the withstand capability of generating units connected prior to the introduction of these standards in 2007.

The Commission notes that the Essential Services Commission of South Australia (ESCOSA) is currently conducting a review of technical licence conditions for non-synchronous generators in South Australia and that additional technical conditions have been placed on new connecting generators based on interim advice received from AEMO. These interim requirements include some conditions related to the provision of frequency control capabilities and RoCoF withstand capability.

Approach to system strength

The key change involved in implementing the Commission's proposed approach to addressing system strength issues will be to amend the rules to clarify that Network Service Providers (NSPs) should be responsible for maintaining an agreed minimum short circuit ratio to connected generators. Generators would continue to be required to meet their registered performance standards above this agreed level.

Where the entry of a new generator would cause minimum short circuit ratios to be breached for one or more existing generators, the NSP would be entitled to recover the costs of the remedial actions from the connecting generator on a "causer-pays" basis. However, the Commission considers it unworkable to seek to recover any costs caused by a generator retirement from the exiting generator; any resulting works would instead be undertaken by the NSP as a prescribed service, which is to say that they would ultimately be funded by consumers.

Clarifying that NSPs must maintain an agreed minimum short circuit ratio to connected generators will address the key risk the Commission has identified in relation to system strength, which is that declining levels of system strength can affect the ability of generators to operate correctly such that they can meet their technical performance standards. This can increase the risk of cascading outages leading to major supply disruptions.

System strength relates to the size of the change in voltage for a change to the load or generation at a connection point. It has recently been decreasing in some parts of the power system as a number of traditional synchronous generators are operating less or are being decommissioned.

Low levels of system strength can additionally degrade the capability of some transmission and distribution network protection systems, which rely on a high fault current to operate effectively, and affect the ability of network operators to manage voltages within their networks. The Commission's view is that, in these cases, the Rules already clearly place the obligation for maintaining the operation of network protection systems and the control of network voltage on the relevant NSP.

There are a range of technical solutions that can be used to address issues stemming from decreased system strength, including upgrading protection systems and installing voltage control devices, reinforcing the network or, ultimately, restoring system strength with additional synchronous machines.

The Commission notes that the allocation of the above roles to NSPs is consistent with its preferred approach for frequency control. Managing inertia and managing system strength are likely to be highly complementary activities, as additional synchronous generators or condensers can be used to resolve both issues. Therefore, investment and operational decisions would be able to be made together in a way which allowed effective and efficient outcomes - particularly in respect of the locational dimension to service provision - to be achieved.

Other system security issues

Maintaining power system security in NEM in the face of a changing generation mix and demand patterns requires the consideration of a range of issues. In this review, and consistent with the views of AEMO, the Commission has prioritised two key issues: frequency control in light of potentially higher levels of RoCoF and the management of system strength as fault levels decrease.

The review is not considering the effectiveness of the FCAS framework more generally, as the Commission considers this to be a less immediate concern. However, there is likely to be merit in a more thorough examination of the framework to see if adjustments would allow frequency to be managed more efficiently.

In particular, the Commission has been made aware of concerns that there has been a deterioration in the frequency control of the power system in recent years and that the provision of all frequency control through a real time market mechanism leads to a greater level of risk than in comparable power systems where frequency control is managed through fixed services with a level of mandated requirements.

An implication of the introduction of the FCAS market into the NEM was the widening of the "deadband" around the normal system frequency. It has been suggested that this has placed a greater reliance on system level frequency control rather than from generator governor response, unnecessarily increasing the level of contingency FCAS required to arrest a change in frequency.

Similarly, the Commission notes that, particularly in light of the "system black" event that occurred in South Australia on 28 September 2016, there is also concern around wind turbine fault ride through capability and voltage dips activating fault ride through.[2]

Through the remainder of the review, the Commission intends to investigate, catalogue and prioritise these broader issues, in order to determine an appropriate mechanism for progressing them where this is warranted.

The current review is also not specifically addressing the "system black" event that occurred in South Australia on 28 September 2016, although frequency management and system strength may well be relevant considerations. The COAG Energy Council has directed the AEMC to undertake a separate review of that event, building on the technical work currently being conducted by AEMO and the investigations being undertaken by the Australian Energy Regulator. AEMO is expected to complete its final report before the end of March 2017.

Next steps

The Commission is seeking stakeholder feedback on the contents of this directions paper, particularly in regards to the proposed approaches to addressing frequency control and system strength issues.

The AEMC's System Security Work Program comprises the System Security Market Frameworks Review and a number of related rule change requests. The Commission has been considering a rule change relating to emergency frequency control schemes separately to the review, and is due to make a final determination on this rule change on 30 March 2017. Three further rule changes relating to frequency control and system strength raise more complex and involved matters, and these are consequently being canvassed through the review. Draft determinations on these rule changes are currently due by 29 June 2017.

The Commission's preliminary view is that the measures set out in the immediate frequency control package and the proposed approach to system strength could be implemented through the existing rule changes. A final report for the review would be published at the same time as the draft rule determinations, setting out how the subsequent frequency control package and the broader issues identified for further consideration would be progressed.

2 Wind turbines have protective features that can result in a significant power reduction if they experience more than a pre-set number of voltage dips within a defined window of time. The Commission understands that some wind farms in South Australia have subsequently increased this pre-set level following the events of 28 September 2016. AEMO, *Black System South Australia 28 September 2016 – Third Preliminary Report*, December 2016, pp. 5-6.

Over the coming months, we will continue to work closely with AEMO and representatives of the technical working group on system security to further assess and develop the detailed arrangements for immediate implementation as we work towards the draft determinations and to finalise the review.

Contents

1 Introduction

1.1 Background

The Australian Energy Market Commission (AEMC or Commission) initiated its System Security Market Frameworks Review to address two key power system security issues:

- **Managing frequency in a low inertia system** - Managing frequency involves balancing the supply of electricity against demand on an instantaneous basis. Large deviations from the normal frequency level or high rate of change of frequency (RoCoF) can cause the disconnection of generation or load, and have the potential to lead to cascading failures. The ability of the system to cope with sudden imbalances of supply and demand is determined by the inertia of the power system, which is provided by spinning generators, motors and other devices that are synchronised to the frequency of the system. However, many new generation technologies, such as wind turbines and photo-voltaic panels are not synchronised to the grid, have low or no physical inertia, and are, therefore, currently limited in their ability to dampen rapid changes in frequency.

- **Managing power system strength** - Non-synchronous generators also do not contribute to system strength as much as synchronous generating units. System strength relates to the size of the change in voltage for a change to the load or generation at a connection point. When the system strength is high at a connection point, the voltage changes very little for a change in the loading; however, when the system strength is lower, the voltage would vary more with the same change in load. Reduced system strength in certain areas of the network may mean that generators are no longer able to meet technical standards and may be unable to remain connected to the power system at certain times. Challenges in maintaining voltage stability and network protection issues may have yet further impacts.

Consequently, the review is considering changes to wholesale energy market frameworks to complement the current shift towards new, non-synchronous forms of generation. The terms of reference require the AEMC to:

- identify the reasons for the proposed change(s) and likely impacts on the power system, the NEM and consumers; and

- describe pathways to implementation, including timing, possible interim stages and any changes to the National Electricity Law or National Electricity Rules.

The impact of non-synchronous generation on power system security was highlighted in the AEMC's Strategic Priorities for Market Development as an important focus in the coming years and this review was initiated by the Commission in July 2016 to continue its work in this area.

Given that under the National Electricity Law, the Australian Energy Market Operator's (AEMO) statutory functions include maintaining and improving power system security (s.49(1)(e)), the AEMC's review is drawing upon work being undertaken by the AEMO, as part of its Future Power System Security (FPSS) Program. The review is adopting the priorities identified by AEMO on current and potential future challenges to maintaining system security. More detailed information regarding AEMO's work on issues relating to the transition to greater levels of non-synchronous generation, and its work on the visibility of distributed energy resources, can be found in AEMO's Future Power System Security Program Progress Reports.[3]

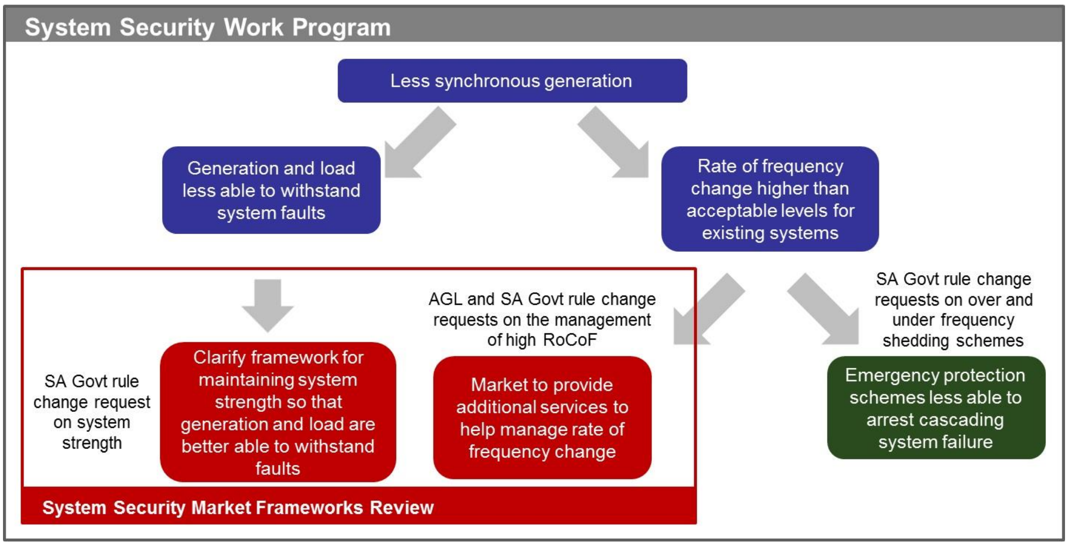
The AEMC's review will identify the changes to market and regulatory frameworks that will be required to deliver the technical solutions identified by AEMO. These changes may include, but are not necessarily limited to, different mechanisms to competitively procure the required system security services, possible changes to standards or the establishment of new standards, or changes to the roles and responsibilities of market participants.

1.1.1 System security work program

The AEMC's System Security Work Program comprises the System Security Market Frameworks Review and five related rule change requests received on system security matters.[4] Four of the rule changes were submitted by the South Australian Government, with the fifth requested by AGL. These rule changes are being progressed concurrently and in coordination with the review.

Figure 1.1 shows the relationship between the issues being considered under the System Security Work Program and how these issues relate to the System Security Market Frameworks Review and the related rule change requests.

Figure 1.1 AEMC System Security Work Program



3 AEMO, *Future Power System Security Program*, Progress Report, January 2017.

4 Information on these rule change requests can be found at www.aemc.gov.au/Rule-Changes.

The AGL rule change request and the South Australian Government's rule change requests relating to inertia/high RoCoF and to system strength are being progressed concurrently and in coordination with the AEMC's Review. Therefore, as the Commission identifies solutions it can move directly to implementation by making rules based on these rule change requests.

However, these three rule change requests deal with a range of complex issues for which technical solutions have not yet been fully explored, both within the NEM as well as internationally. The Commission initiated the System Security Market Frameworks Review as a vehicle to coordinate the assessment of these inter-related issues and develop appropriate recommendations for future policy changes. Accordingly, the Commission has extended the period for making the draft rule determinations with respect to these rule change requests by 29 June 2017.

The South Australian Government's rule change requests regarding over and under-frequency shedding schemes are being progressed separately to the review and the other three rule change requests. These rule change requests seek to refine the existing arrangements for emergency under-frequency control schemes and to establish a regulatory framework for over-frequency control schemes, respectively. Changes to the rules arising from these rule change requests may address some of the more immediate concerns in relation to the governance and operation of emergency protection schemes, particularly as it applies to managing the impact of a sudden separation of South Australia from the rest of the NEM.

As these two rule change requests relate to similar matters, the Commission decided to consolidate them into a single rule change under s.93(1) of the National Electricity Law. In accordance with the statutory timelines, the Commission published a draft determination for the combined rule change on 22 December 2016. The Commission currently anticipates publishing the final rule determination on 30 March 2017.

1.2 Outline of this paper

This paper:

- provides an overview of the issues associated with the management of power system frequency identified in the review's interim report;
- assesses the options to obtain additional frequency related services set out in the interim report;
- presents the Commission's proposed approach to frequency;
- provides a more detailed discussion of the issues associated with system strength than was contained in the interim report, and sets out the Commission's proposed approach in this regard; and
- outlines the process for making submissions.

1.3 Overview of power system frequency issues

The interim report identified the factors that influence the ability to maintain control of power system frequency following a contingency event, such as the loss of a large generator, load or transmission line.[5] These can be considered through the following three-part framework:

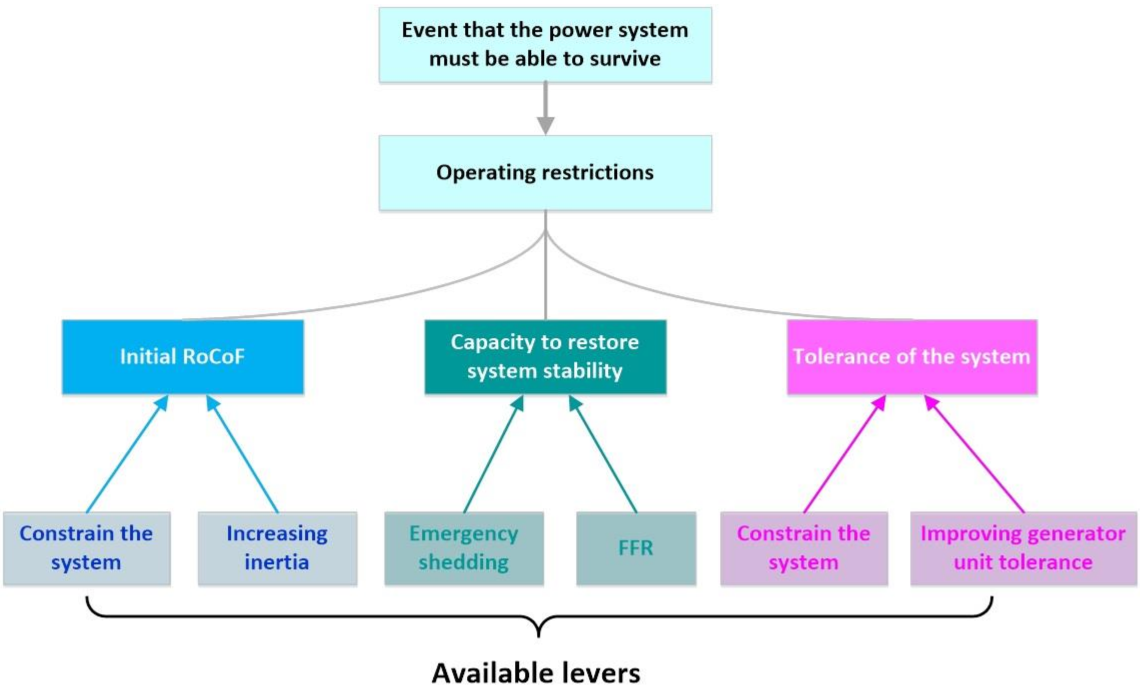
1. The initial RoCoF, influenced by the size of the contingency and the level of system inertia.

2. The capacity to restore the stability of the system through the use of frequency response services.

3. The ability of generators and loads to withstand or "ride-through" changes in frequency.

This framework is illustrated in Figure 1.2.

Figure 1.2 Factors that influence the control of power system frequency



1.3.1 Initial rate of change of frequency

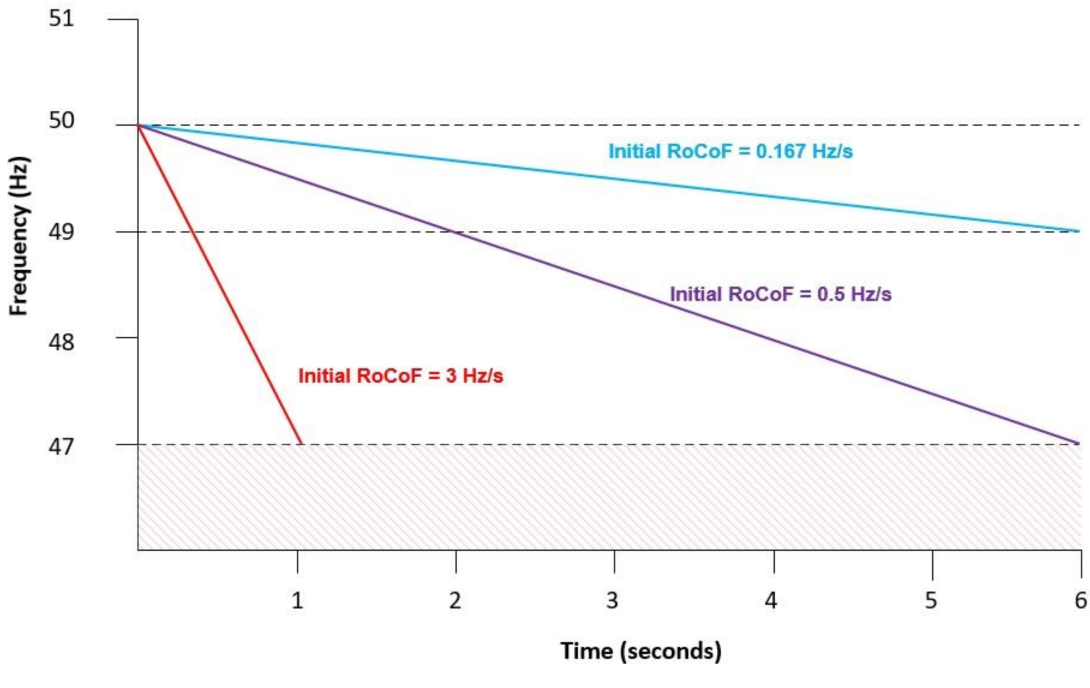
The rate at which system frequency changes determines the amount of time that is available to arrest any decline or increase in frequency before it moves outside of the permitted operating bounds.

5 For the full discussion, see: AEMC, *System Security Market Frameworks Review*, Interim Report, 15 December 2016, Chapter 3.

Figure 1.3 illustrates how the rate that the frequency changes determines the amount of time available. The three lines in the figure show the potential impacts on the level of frequency from different levels of initial RoCoF. The figure assumes that a loss of generation occurs with the system frequency at 50 Hz, that there are no services available to arrest the decline in frequency until six seconds after the contingency event – the time period associated with the current fastest response service[6] – and that all generating units can tolerate the frequency change:

- For the frequency to remain within the current operational frequency tolerance band (above 49 Hz), the initial RoCoF cannot exceed 0.167 Hz/s (blue line).
- For the frequency to remain within the current extreme frequency excursion tolerance limit (above 47 Hz), the initial RoCoF cannot exceed 0.5 Hz/s (purple line).
- An initial RoCoF of 3 Hz/s would lead to the frequency falling below the extreme frequency excursion tolerance limit after one second (red line).

Figure 1.3 Initial RoCoF determines the time available to respond



Prior to the occurrence of a contingency event, there are two actions that could be taken to minimise the resulting initial frequency change:

- constrain the power system to minimise the size of the contingency; and/or
- increase the level of inertia in the system to resist the initial frequency change.

6 It should be noted, however, that in practice the response takes effect over the six second period rather than precisely at the six second mark. It should also be noted that the system frequency at the time of the contingency may not be exactly 50 Hz. Under normal operating conditions, the system frequency may be as low as 49.75 Hz.

For credible contingencies, AEMO has the ability to introduce constraints, in order to maintain system security, that alter the operation of the power system. Constraints to control the RoCoF would limit the maximum contingency size, relative to the amount of inertia online. However, the effect of a binding constraint is likely to be an increase in the wholesale electricity price. For example, a constraint that restricts flows on an interconnector may limit the ability of power to be sourced from a lower priced generator in another region.

An alternative to constraining the system to limit the contingency size would be to increase the level of inertia in the power system. A higher level of inertia would permit the occurrence of larger contingencies for a given level of initial RoCoF.

There is currently no ability for AEMO or any other party to obtain and pay for additional inertia. In the past, inertia has been plentiful and so such a mechanism has not previously been required. The Commission therefore reached a preliminary view that the ability to maintain power system security in an efficient manner would be enhanced by the development and introduction of a mechanism to obtain and pay for inertia.

Such a service could be provided by any synchronous machine, including synchronous generators, mechanical loads and synchronous condensers. Synchronous condensers are large machines similar to those used in synchronous generating units but not including turbines to convert the energy from a fuel source to electrical energy.

International experience suggests that it is not currently possible to operate a large power system without some synchronous inertia, and that “synthetic” inertia from non-synchronous generators does not provide a direct replacement.[7] Consequently, any inertia service in the NEM would have to initially be provided by synchronous machines.

However, in the future, it may become possible to use inverter-connected devices (such as energy storage devices) to constantly and “instantaneously” maintain frequency.[8] Consequently, the inertia service should be defined in such way as to accommodate new technology options.

1.3.2 Capability to restore the supply-demand balance

Limiting the initial rate of change of frequency will only act to increase the amount of time before frequency moves outside of acceptable bands. Inertia does not act to arrest the frequency change or revert frequency back to normal operating levels.

In the NEM, AEMO is responsible for maintaining the system frequency within the Frequency Operating Standards (FOS). Under the FOS, AEMO is required to maintain the system frequency within the operational frequency tolerance band of 49.0 to 51.0Hz for a reasonably possible ("credible") contingency event.

7 DGA Consulting, *International Review of Frequency Control Adaption*, 14 October 2016, p. 3.

8 DGA Consulting, *International Review of Frequency Control Adaption*, 14 October 2016, p. 3.

To maintain system frequency within these limits, AEMO is able to procure Frequency Control Ancillary Services (FCAS). In particular, "contingency FCAS" is used to control frequency in response to major variations caused by contingency events such as the loss of a generating unit or a significant transmission line. Contingency FCAS acts to arrest steep rates of change of frequency and then stabilises and recovers the system frequency over time to bring it back to within the normal operating frequency bands.

There are six contingency FCAS markets: up to six-second, 60-second and five-minute markets for both raise and lower services. The six-second service is therefore currently the quickest acting. As shown above in Figure 1.3, in the event of a frequency deviation away from 50 Hz, for the system to remain within the current requirements of the FOS requires relatively low levels of RoCoF compared with those now possible in the NEM, notably in an islanded South Australia.

Fast frequency response as a tool to manage frequency

To permit a greater potential level of RoCoF for credible contingency events would therefore require the development of a faster-acting contingency FCAS, which has come to be termed a "fast frequency response (FFR) service". FFR services would provide greater flexibility in the level of RoCoF that could be permitted and, hence, allow a more efficient amount of inertia to be procured. The Commission consequently considers that a long-term solution to managing frequency in a low inertia system should aim to facilitate the use of fast-frequency technologies.

The Commission notes that AEMO is currently undertaking detailed work on a technical specification for a FFR service.[9] However, such a service might be expected to act somewhere in the range of half a second to two seconds. A one-second service would imply that a RoCoF of 1 Hz/s could be permitted and the system still remain within the current operational frequency tolerance band.[10]

While synchronous generators currently provide the majority of six-second raise FCAS, it appears unlikely that such generators would be able to respond in the timeframes demanded by a FFR service. Rather, this faster response might be provided by inverter-based generators such as wind turbines, by energy storage devices and by demand-response schemes.

Fast frequency response services are not a mature technology and no international jurisdiction has any significant experience operating a FFR-type service. However, a two-second FFR service was implemented in Ireland in October 2016 and a one-second demand response service is used in New Zealand.[11] Consequently, the Commission's

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9 AEMO, *Future Power System Security Program*, Progress Report, January 2017, p. 8. See also AEMO's interpretation of the key findings of a report prepared for AEMO by GE Consulting on a potential fast frequency response service : https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/FFR-Coversheet-2017-03-10a.pdf

10 This assumes that the system frequency is at precisely 50 Hz at the time of the contingency event.

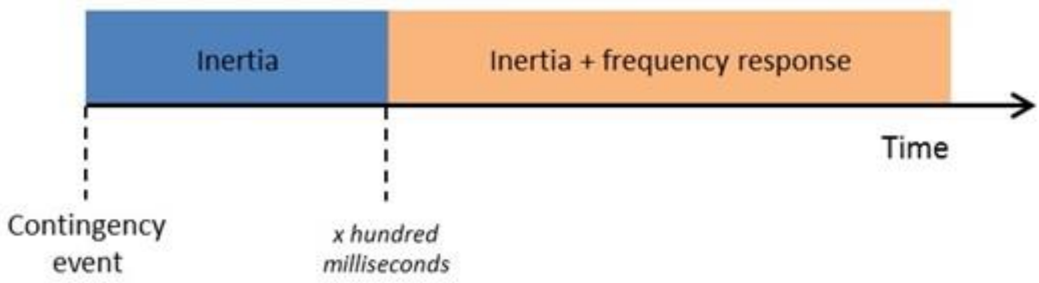
11 DGA Consulting, *International Review of Frequency Control Adaptation – Report for the Australian Energy Market Operator*, 14 October 2016, pp. 89 & 111.

preliminary view is that the technology is likely to be sufficiently advanced as to support the specification of such a service now and to allow technical options for its provision to develop over time.

While a number of technologies exhibit very rapid response times, the physical realities of accurately measuring frequency changes may limit the response capabilities of FFR technologies.

The time delay of FFR technologies implies that there is a minimum level of inertia that must be online at any point in time to resist frequency changes caused by contingency events. The inertia would slow the frequency change to provide time for frequency response services to be activated. Beyond this initial time period, fast frequency response technologies have the potential to be used in combination with inertia to stabilise system frequency. This distinction between the roles of the two services is illustrated in Figure 1.4 below.

Figure 1.4 Timeline for inertia and fast frequency response



1.3.3 Tolerance of the system

In designing a framework for inertia and FFR services, and consequently a RoCoF limit, it will be important to understand the tolerance of all parts of the system to that level of RoCoF. A RoCoF limit of 2 Hz/s would not be effective if the maximum RoCoF that could be tolerated by individual generators and loads was 1 Hz/s.

In practice, generators and loads will have a range of withstand capabilities. While it will likely be important to understand these in general, that will particularly be the case for equipment providing inertia and FFR services. For example, a generator contracted to provide inertia would need to be able to withstand RoCoF to at least the targeted RoCoF limit.

The performance standards relating to the ability of generators to withstand rates of change of system frequency are set out in the National Electricity Rules (NER or rules). These standards have been imposed as a condition of generator connection agreements since 2007.

The current standards are automatically met if a generating unit can withstand a RoCoF of ±4 Hz/s for quarter of a second. Generators may negotiate a lower standard, but the minimum standard is ±1 Hz/s for one second. There is no obligation on generators to remain connected to the system through an event where RoCoF exceeds those levels, even if the frequency remains within the bounds of the FOS.

The withstand capability of generators that connected prior to 2007 is largely unknown. While historical incidents can provide some indication of the withstand capability of these generators, the capability of any particular generator to withstand high RoCoF is largely dependent on the operating and market conditions that were present at the time of the event.

1.3.4 Options to obtain additional system security services

In addition to identifying the issues associated with frequency management, the interim report also set out a number of potential options to address these - that is to say mechanisms for obtaining inertia and fast frequency response services.

The potential mechanisms for the provision of additional system security services were grouped into four broad options, as follows:

1. *Generator obligation* – The imposition of a minimum technical standard on each generator in the NEM, which could involve:
   (a) an obligation on generators to physically acquire or build the necessary equipment to meet the standard; or
   (b) an option for generators to enter into an agreement with another provider.
2. *AEMO contract process* – The procurement of services via contracts with individual market participants through a competitive tender process or bilateral negotiated process undertaken by AEMO.
3. *TNSP provision* – The direct provision of services by transmission network service providers (TNSP) or the procurement of services by TNSPs under a modified Network Support and Control Ancillary Service (NSCAS) framework.
4. *Five-minute dispatch* – Prices are set for the services on a five-minute basis, which could involve:
   (a) the services incorporated in the dispatch process with a price paid to providers based on the value of the service in the five-minute dispatch interval; or
   (b) a separate market with offers submitted by providers of the services and a price determined for each five-minute interval.

The Commission noted that over the following stage of the review, it intended to refine and narrow the range of potential options to deliver the system security services based on stakeholder feedback and assessment against a number of guiding principles identified.[12]

1.4 Structure of this report

The remainder of this directions paper is structured as follows:

- Chapter 2 discusses the key considerations for assessing the different mechanisms for managing frequency issues that were set out in the interim report;
- Chapter 3 evaluates and compares the effectiveness of the different mechanisms;
- Chapter 4 sets out the Commission's proposed approach to frequency;
- Chapter 5 provides:
  - more detailed discussion of the factors relevant to maintaining levels of system strength; and
  - the Commission's proposed approach to addressing issues arising in relation to system strength.

12 The guiding principles comprise risk allocation, certainty versus flexibility, technology neutrality and competition. See: AEMC, *System Security Market Frameworks Review*, Interim Report, 15 December 2016, p. 5.

2 Key considerations for evaluating the mechanisms

Box 2.1 Summary

Each of the four potential mechanisms to procure additional system security services identified in the interim report could in principle be adopted on its own to manage changes in system frequency. However, there are a number of aspects of power system security that could also be impacted by the adoption of these mechanisms. These aspects, as set out below, are likely to be affected differently depending on the mechanism chosen. As such, a combination of the mechanisms may represent the most efficient overall solution to the ongoing management of power system security.

- *Level of services required*: There is a minimum absolute threshold level of inertia required to be provided at all times in order to maintain stability in the power system. Beyond this minimum level, greater levels of inertia or FFR can provide market benefits by improving the power transfer capability of the network. That is, allowing for greater output from generators and increased energy flows on the network.

  An operating level of inertia could be determined that would be provided to the system at all times. This required operating level would represent a workable level of inertia that could satisfy a range of, but not all, system conditions. The mechanism used to provide the required operating level of inertia may be different to the mechanism that would most efficiently determine the economic trade-off between more inertia, more FFR, or alleviating constraints on the network.

- *Inertia and FFR are distinct services*: Inertia and FFR can both be used to manage changes in system frequency caused by a contingency event. However, the distinct characteristics of each service may mean that separate mechanisms would be better suited to the efficient procurement of each of these services.

- *Location of services in the network*: The location of sources of inertia and FFR in the system has implications for the management of system security. The location of the services may have an impact on the ability to manage frequency under some circumstances. Equally importantly, other aspects of system security including system fault levels and voltage control are likely to be substantially impacted by the network location of the services.

2.1 Determining the level of services required to manage power system security

The level of system inertia determines the size of the immediate RoCoF that would result upon the occurrence of a contingency of a given size. Limiting the size of the RoCoF would provide:

- a higher probability of generators remaining online following the occurrence of a contingency event;
- time for emergency frequency control schemes to operate effectively; and
- time for frequency control ancillary services to respond and recover the frequency to normal operating levels.

Each of these aspects contributes to the system frequency remaining within the bounds of the FOS.

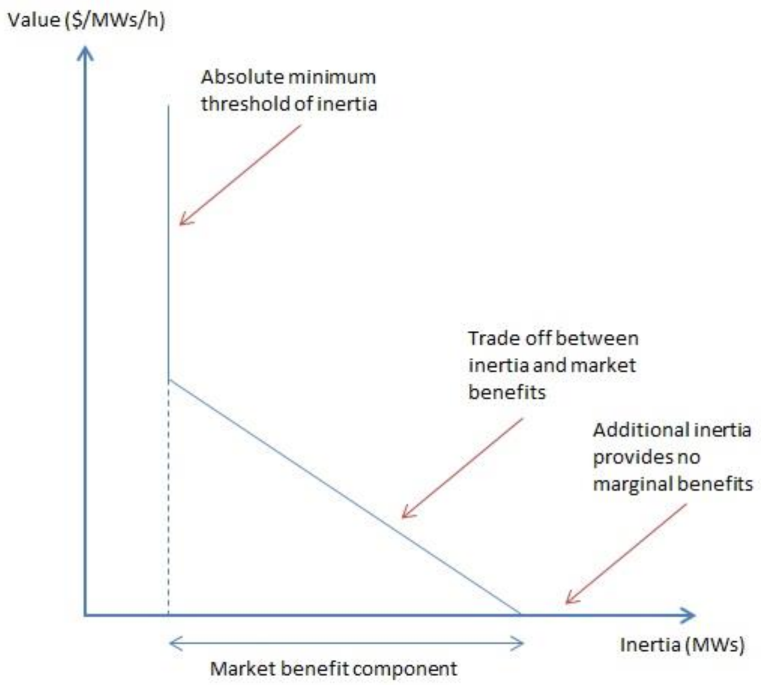
The level of inertia that is required to maintain the RoCoF to a given limit can be divided into two components:

1. **Minimum system threshold** – The absolute minimum level of inertia that is required to maintain the secure operation of the system. The absolute minimum level represents a lower bound on the level of inertia that is required to feasibly operate the system. Operating at this minimum level may require load shedding but would be sufficient to operate the islanded system to avoid a system black condition. This minimum level might not permit any interconnector flow, or limited flows, prior to separation.

2. **Market benefits** – Additional inertia above the minimum threshold would allow additional interconnector flows, improve reliability, and lower the overall cost of energy provision by alleviating constraints on the system.

The split between these two components is illustrated in figure 2.1, which shows a theoretical demand curve for inertia.

Figure 2.1 Value of inertia and the amount of inertia provided

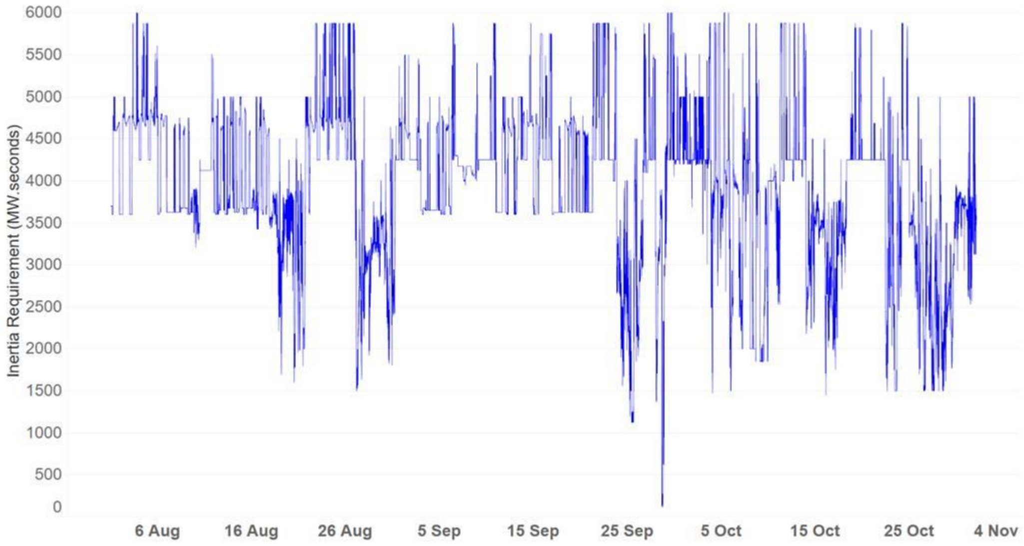


The vertical line on the left represents the absolute minimum system threshold of inertia. This vertical line is a lower bound on the level of inertia that could feasibly be required in order to operate the system within the FOS. Beyond this level, the sloped line represents the trade-off that exists between the costs of supplying more inertia and other options for managing system security, such as constraining the system or obtaining FFR services. A continuation of the line shows that any additional inertia supplied to the market has no effect in further alleviating constraints on the system and so provides no additional benefit for either maintaining system security, improving reliability, or lowering the overall cost of energy production.

Figure 2.1 represents a theoretical trade-off between increasing levels of inertia and obtaining market benefits. This trade-off is unique to the specific set of operating conditions present in the system at a given point in time. In practice, the level of inertia required to limit RoCoF and maintain the secure operation of the power system varies with changing system conditions.

Figure 2.2 shows how inertia requirements can vary over time depending on the prevailing system and network conditions. The figure shows the level of inertia that would have been required over the period August to October 2016 to maintain the RoCoF to 1 Hz/s for the loss of the largest generating unit in South Australia.

Figure 2.2 Variability of required inertia



The required operating level of inertia

In order to manage the secure operation of the power system under a range of system conditions, a level of inertia above the absolute minimum system threshold would need to be provided.

A mechanism that guarantees the provision of inertia only up to the absolute minimum system threshold would only be sufficient under specific highly constrained conditions and is therefore unlikely to be practical for the ongoing operation of the power system.

A higher operating level of inertia would be more suitable to enable the secure operation of the power system under a much larger range of system conditions. This operating level of inertia would be higher than the absolute minimum system threshold and would therefore also provide some market benefits.

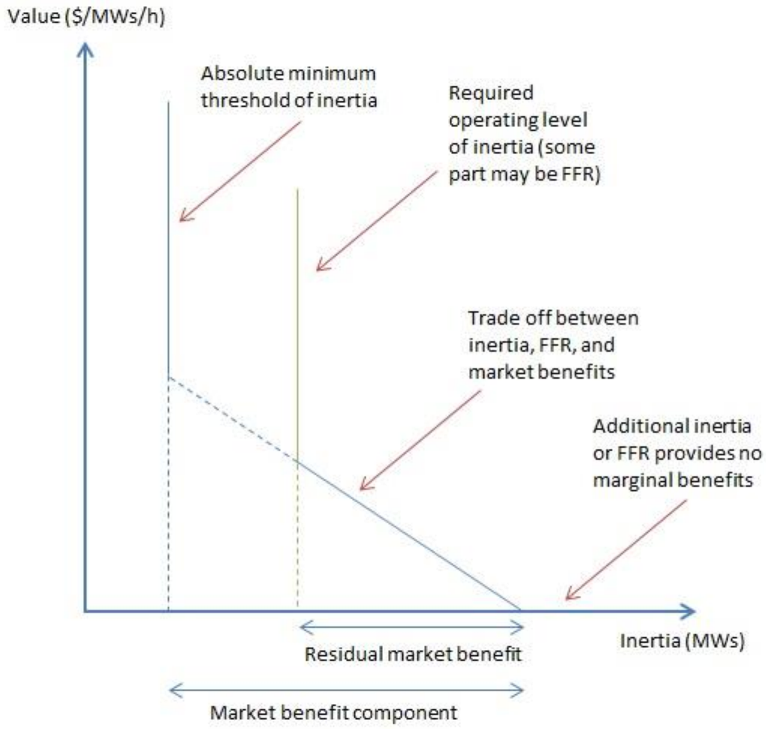
It is probable that the required operating level of inertia would be lower than the absolute highest level of inertia beyond which there are no additional market benefits. It is unlikely to be efficient to provide a required operating level of inertia up to the point at which there are no further market benefits. A mechanism that guarantees inertia up to this level at all times is unlikely to be efficient, particularly as the market may only require this much inertia for brief periods of the year to allow for a fully unconstrained network.

As such, the required operating level would represent a workable level of inertia to be provided at all times to satisfy a range, but not all, system conditions. A prescribed approach to determining the exact required operating level would need to be developed. It is expected that the prescribed approach would set a level that is sufficient for most generating units and transmission lines to be able to operate at some defined level of their capacity and for the region in which the inertia is procured to operate securely as an island from the rest of the NEM. The process used to determine the required operating level of inertia is discussed further in section 4.2.1.

Figure 2.3 shows the required operating level of inertia in comparison to the absolute minimum system threshold level and the market benefit component. The required operating level of inertia allows for the alleviation of constraints on generating units and the network up to a certain level and therefore provides a degree of economic benefit to the market. As such, some of the inertia provided to meet the required operating level could be substituted by FFR. The purpose of a mechanism which guarantees the provision of inertia up to the required operating level is to provide a high degree of confidence that system security can be maintained under a range of operating conditions. Given the relative immaturity of most FFR technologies, the procurement of FFR as a substitute for part of the required operating level of inertia would necessitate a thorough technical assessment and a high degree of operational scrutiny.

As discussed, the process used to determine the required operating level of inertia would not target a specific level of market benefit. However, some level of market benefits would be provided as a consequence. Above the required operating level there is a further residual market benefit that can be obtained through the provision of additional inertia or FFR.

Figure 2.3 The required operating level of inertia



The mechanism that is used to provide the required operating level of inertia must be capable of providing a high degree of certainty that the inertia will be available at all times. The extent to which the required operating level of inertia is likely to be provided over the long term may be dependent on the level of certainty that can be provided in relation to investment.

For any additional inertia provided above the required operating level, there are economic and reliability benefits to the market from increasing the power transfer capability of the network. This additional level of system security services will need to rely on a mechanism that provides certainty to investors. However, it also requires that the same mechanism provide flexibility in the provision of the services to adapt to short-term changes in market conditions to achieve an economically efficient outcome. An efficient market outcome would be achieved where the lowest cost combination of inertia, FFR and constraints on the network were provided.

2.2 Inertia and fast frequency response are distinct services

Inertia and FFR are distinct services which perform different roles in the management of system frequency. Inertia acts to slow the rate of frequency change caused by a contingency. This is different to FFR, which actively injects power to arrest the frequency change and revert the frequency back towards normal operating levels.

However, the two services are, to some extent substitutes: greater amounts of FFR, or faster acting FFR services, will reduce the amount of inertia required. Consequently, co-optimisation of the services would likely lead to lower overall cost arrangements.

The ability to substitute inertia for FFR will be influenced by a number of factors, as discussed below.

2.2.1 Response to frequency change

The instantaneous RoCoF following the occurrence of a contingency event is influenced by the level of inertia in the system and the size of the contingency. The speed at which the frequency changes determines the amount of time that is available to arrest the decline or increase in frequency before the frequency moves outside of the fixed bounds of the FOS.

Inertia does not act to arrest the frequency drop entirely or revert frequency back to normal operating levels. A system with high levels of inertia but with no frequency control or ability to shed generation or load would merely see the frequency move outside of the bounds of the FOS more slowly.

The level of inertia provided is an inherent physical property of a synchronous generating unit and acts to dampen changes in system frequency following a sudden shift in generation or load. This is different to frequency response services which involve a power injection following a change in frequency in order that the system frequency can be stabilised back to normal operating levels.

As such, all frequency response services involve a time delay following the change in generation or load, with some response services being faster than others. Even FFR technologies involve a time delay between the initial change in frequency and the frequency response. This delay is comprised of four separate components which sum to equal the total time to respond:[13]

- **Measurement** – The change in frequency must be measured over a period of time in order to determine the appropriate response. An inaccurate measurement of the change in frequency has the potential to result in a frequency response that is either insufficient to correct the frequency change or may overcompensate which may force the frequency to change in the opposite direction. Alternatively, a response could be inadvertently activated for normal deviations in frequency.

- **Signalling** – Measurement of the frequency change then needs to be communicated to the device providing the frequency response. This signalling may take time depending on the distance between the point of measurement and the device and the speed of the communications equipment being used.

- **Activation** – Once the device received the signal, it may then require time to activate the response. The length of the activation time depends on the power electronic converter being used and the type of FFR device behind the power electronic converter.

13 DGA Consulting, International Review of Frequency Control Adaptation – Report for the Australian Energy Market Operator, 14 October 2016, pp. 60-62.

- **Ramping** – The final component of the response period is the time taken for the FFR device to ramp up from the point of activation to its maximum response output.

The time delay of FFR technologies therefore implies that there is a level of inertia that must be online at any point in time to resist frequency changes at the time of the contingency event as well as over the first few hundred milliseconds following a contingency event. Beyond this initial time period, FFR technologies have the potential to be used in combination with inertia to stabilise system frequency.

Given the time delay of fast response services, the implication is that it would be necessary to design a mechanism which would provide for sufficient inertia to be online to limit high RoCoF at the time of, and immediately following, the occurrence of a contingency event. The same mechanism, or a separate mechanism, could then be used to obtain fast frequency response services to stabilise frequency after the initial time period.

2.2.2 Fault ride-through capability of FFR services

Faults in the transmission system can quite often be the cause of contingency events. Under these circumstances, inverter connected generation can be limited in its ability to provide active power to the network. This limitation is greater the closer the proximity to the fault. Inverter connected technologies cannot provide FFR services until such time as the fault is cleared.

Faults in a power system are a short circuit between the conductors in the power system. This can occur between the conductors on a transmission or distribution line when it is struck by lightning, the conductors are exposed to bush fires or when an insulator is damaged. Faults can also occur within items of electrical plant such as transformers or reactive banks when the plant is damaged.

It is important that the item of plant where the fault is located is isolated from the remainder of the power system. This is often referred to as 'clearing the fault' and is essential so that:

- damage to equipment is limited;
- safety is maintained; and
- the remainder of the power system can continue to operate.

The speed at which the faults are cleared is critical to both limit the risks of damage and to safety, as well as to the ongoing operation of the power system. The maximum allowable fault clearance times for different voltage levels are in Table S5.1a.2 of the NER. The table specifies faster clearance times for high voltages as the consequences of prolonged faults are greater. Clearance times vary between 80 and 430 milliseconds depending on the nominal voltage at the fault location.

Following the clearance of a fault, the active recovery time of the inverter-connected technology is influenced by the strength of the system, with slower recovery times occurring in weak systems. The provision of FFR services by wind generators is an example of a technology that is affected by system strength. The ability to provide power injections following disturbances is usually dependent on voltage stability and a weak system may suppress the ability for wind generators to provide a frequency response.

The period of time required to clear faults is likely to have an impact on the minimum response time capability of FFR services, which may limit the extent to which FFR can be relied upon as a substitute for inertia.

2.2.3 Specification of FFR services

There are a variety of different technologies that have the potential to provide a fast frequency response contingency service to manage sudden changes in system frequency. Each of these technologies may provide these services with distinct operational characteristics, including whether the service is capable of rapidly injecting as well as withdrawing active power, whether the service is capable of sustaining the delivery of active power over a period of time, and the specific profile of the power injection in response to the frequency change.

Raise and lower services

FFR technologies operate in a similar manner to existing frequency control services in the NEM but over a shorter timeframe. As such, the requirements for the service are likely to be symmetric with active power injected as a raise service to increase frequency and rapid withdrawal of power as a lower service to reduce frequency.

Typically, the rapid withdrawal of power is much less expensive and is easier to achieve in practice than rapid controlled injections of power. This is because most technologies must maintain some reserve capacity to provide the raise service, which entails an opportunity cost. Whereas almost any inverter connected technology can rapidly reduce power output at any time.[14]

Recovery period

There are a number of FFR technologies that are capable of providing rapid power injections in response to a frequency change but are either limited in the duration of that response or require a period of time following the power injection to recover power output.

FFR from wind turbines is an example of a technology that involves a recovery period.[15] Wind turbines provide a FFR response by rapidly converting energy stored

14 There may be an opportunity cost associated with foregone spot market revenue or renewable energy certificates.

15 GE Energy Consulting, *Technology Capabilities for Fast Frequency Response – Final Report*, 9 March 2017, p. 41.

in the rotating blades to an active power injection. This has the effect of slowing the rotational speed of the blades and a period of time following the power injection is required for the blades to return to the original speed.

The use of FFR technologies that involve recovery periods must be coordinated with the availability of other slower frequency response services, such as the six-second FCAS, in order to maintain a controlled reversion of frequency to normal operating levels following a contingency event.

This is also true of some other technologies such as supercapacitors which are capable of providing a very rapid but limited power injection in response to a sudden change in frequency. While not requiring an immediate recovery period, the use of these technologies must still be coordinated with the use of other slower response technologies in order to provide a controlled management of system frequency.

Profile of response

Control systems on FFR services determine the profile of the response to frequency changes following a disturbance.[16] The profile of the response can either be open-loop or closed-loop. An open-loop response provides a pre-set power injection based on a triggered signal, such as a local measurement of frequency. A closed-loop response provides a proportionate response based on a continuous measurement of system frequency. Closed-loop controls are likely to be able to provide significant stability benefits but are generally more expensive than open-loop controls.

2.2.4 Maturity of FFR technologies

Fast frequency response services are not a mature technology, and are at an early stage of development or deployment. There are only limited examples of fast frequency response technologies being used to provide a contingency service in major power systems in the world. EirGrid in Ireland has recently implemented a FFR contingency service triggered by local frequency change.[17] This service is based on a response time of two seconds.

Consequently, the ability to substitute inertia with FFR technologies is to be limited initially, but is also likely to increase over time as experience is gained through active use in power systems. The Commission noted in the interim report that there are a range of technologies that have the potential to provide FFR services, including wind, solar PV, battery storage, load based resources and HVDC transmission.[18]

The Commission therefore considers that a long-term solution to managing frequency in a low inertia system should anticipate the use of fast-frequency response

16 GE Energy Consulting, *Technology Capabilities for Fast Frequency Response – Final Report*, 9 March 2017, p. 42.

17 DGA Consulting, International Review of Frequency Control Adaptation – Report for the Australian Energy Market Operator, 14 October 2016, pp. 111-112.

18 See: AEMC, *System Security Market Frameworks Review*, Interim Report, 15 December 2016, pp. 29-30.

technologies. In the shorter term, consideration should be given to mechanisms that allow FFR services to be developed and trialled.

2.3 Location of the services in the network

The location of sources of inertia and FFR in the system has implications for the management of system security. The location of the services may have an impact on the ability to manage frequency under some circumstances. Equally importantly, other aspects of system security including system fault levels and voltage control are likely to be substantially impacted by the network location of the services.

Managing system frequency

The location of synchronous devices that are connected to the network can have an influence on the ability to control system frequency in the event of a contingency. The loss of transmission lines can have the effect of isolating areas of the network from the rest of the grid. The ability to maintain a secure power system within the isolated area depends on the level of inertia that is available within the area.

Therefore, while the region most impacted by ongoing locational requirements would be Tasmania, which is permanently synchronously isolated from the rest of the NEM, the most relevant example is the requirement to maintain minimum levels of inertia in South Australia in order to maintain power system security within the islanded region should the Heywood Interconnector trip.

However, this concept can equally be applied to some other areas of the power system, including other whole regions and potentially areas within regions. The separation of north Queensland from south Queensland is a possible example of such intra-regional islanding.

Managing system strength

As discussed further in chapter 5, an additional emerging power system security challenge is reducing system strength in some areas of the network. A secure operating system requires generating units and network components to be able to operate continuously following a major fault or disturbance to the power system, and this ability is diminished by declining system strength.

As compared to system frequency, system strength has much more localised impacts. The system strength at a point in the power system depends on how well it is connected to the synchronous generating units in that part of the power system. The system strength will be higher when:

- there are a number of large generating units nearby; and
- the point is connected to these generating units with more transmission (or distribution) lines and transformers.

Non-synchronous generators do not contribute to system strength as much as synchronous generating units, if at all.[19] Procurement mechanisms for frequency control, which might lead to investments in new synchronous devices, should therefore be able to consider the location of such investments in order to co-optimise this with any investment required to manage system strength.

19 Some modern inverter based generation can provide a limited contribution to system strength.

3 Comparison of mechanisms for procuring system security services

Box 3.1 Summary

The Commission presented four potential mechanisms to procure inertia and FFR in the interim report. Since then, we have further developed and assessed these options. This chapter discusses the effectiveness of each of the mechanisms in addressing the key considerations identified in chapter 2.

While some of the options have clear advantages and disadvantages, others may be more suited to procuring inertia and others to FFR or to implementation in the short or longer term. The key findings are as follows:

- *Generator obligation* - Although a conceptually simple solution, setting the level of the obligation would be difficult. Certainty over the level would be required to underpin investment, but would limit flexibility to deal with changing circumstances or target a precise level of market benefits. The interaction with energy dispatch would be complex, and there would likely only be limited ability to optimise the location of service provision. Imposing an obligation on existing generators might be difficult, and limiting the obligation to centrally-dispatched generators may be ineffective in the long term as the penetration of distributed energy resources (DER) increases.
- *AEMO contracting* - AEMO procuring inertia and/or FFR through contracts may provide the certainty required for investment, while also allowing some flexibility. However, it may be difficult to develop clear criteria by which AEMO could assess competing, disparate offers. Consumers would bear all the risks of any under or over-procurement. AEMO would need to liaise closely with network service providers (NSP) to ascertain where system strength requirements lie.
- *TNSP provision* - TNSPs would be able to offer certainty when procuring or themselves providing the required level of inertia. The identification of market benefits fits well with existing TNSP planning frameworks, and it would be possible to place financial incentives on TNSPs to drive efficient levels of provision. TNSPs would also be well placed to coordinate inertia provision with system strength requirements.
- *Market sourcing* - A spot market for inertia may not provide the necessary levels of certainty to prospective investors without a liquid secondary contract market, and the physical properties of inertia may make it difficult to incorporate into the existing market design. While FFR services are likely to be more easily accommodated within existing market structures, additional experience may be required before a service could be properly specified. Market sourcing may be limited in its ability to cater for system strength issues.

This chapter provides a brief overview of the four potential procurement mechanisms set out in the interim report, and includes additional detail where we have further developed the options. Each option is then assessed against the key considerations set out in chapter 2.

3.1 Generator obligation

An obligation placed on generators could be used to provide the required level of services to maintain power system security. This could involve:

(a) an obligation on generators to physically acquire or build the necessary equipment to meet the standard; or

(b) an option for generators to enter into an agreement with another generator or inertia provider for the required level of inertia.

As outlined in the interim report, there are two conceivable approaches for establishing the level of the technical obligation that must be met by generators:

1. Generation online – the minimum standard would be specified in terms of MW.s per MW of generator capacity online. Effectively, generators would be obliged to provide a level of inertia proportional to their output at a given point in time.

2. Installed capacity – the minimum standard would be set in terms of MW.s per MW of installed generation capacity. Effectively, each generator would be required to provide a fixed level of inertia on a continuous basis. There may also be an option to set the minimum standard in terms of MW.s per MW of installed generation capacity weighted by a factor relating to the characteristics of differing generation types.

The obligation could be applied exclusively to new entrants or also to existing generators.

3.1.1 Providing the required level of system security services

A key consideration of imposing an obligation on generators to provide the required services is the level at which the obligation would be set. Setting the level of the obligation would require a consideration of whether generators should only be required to provide sufficient inertia to meet the required operating level, or whether additional inertia should be provided to alleviate network constraints and improve the capability of the network. A consideration of this trade-off may be at odds with the notion of a technical obligation.

In addition, the level of the obligation is unlikely to be able to significantly vary over time. Mandating an obligation on generators to provide a minimum level of inertia would provide investor certainty. However, in order to minimise costs on generators, the level of the obligation is likely to have to be determined upfront. As such, there is a risk that a generator obligation may be under or over-specified, increasing the costs of maintaining system security over the long term.

Further, imposing new requirements on existing generators might be challenging legally and raise potential sovereign risk concerns. However, an obligation imposed only on new entrants may require the obligation on each generator to be set at a high level to provide the minimum amount of inertia that is required to maintain a secure system. This has the potential to impose significant costs on new entrants, which could result in significant barriers to entry and a delay to the provision of the required levels of inertia.

Another consideration in setting the level of the obligation is the ability of generators to withstand high rates of frequency change caused by contingency events. The lower the withstand capability of generators, the higher the inertia obligation would need to be imposed on generators. The generator with the lowest withstand capability could therefore potentially make a significant difference to the inertia obligation imposed on other generators, and this may need to be taken into consideration when imposing obligations on specific generators to provide inertia.

Box 3.2 Applying the obligation

There are two conceivable approaches to applying a generator obligation, once a level has been set: generators could be obliged to provide a level of inertia proportional to their output at any given point in time or, alternatively, as a fixed amount on a continuous basis irrespective of whether or not they are online.

Under the generation online approach, the level of inertia provided to the system would change as generation output varies over the course of the day. While intuitively similar to situations in the past where inertia was provided by plant generating, the level of inertia provided may actually correlate poorly with the size of potential contingencies and increased threats to system security. Indeed, there may be times in the not too distant future in South Australia when there may be minimal centrally-dispatched generators online.

Alternatively, an obligation that is required to be provided at all times irrespective of whether or not the generating unit is online may result in a considerable risk of over-procuring the required level of inertia. The fixed level of the obligation would likely need to be conservative in order to accommodate a wide range of possible system conditions, potentially placing substantial or even prohibitive costs upon generating units that operate infrequently. Equally, generators with high capacity factors would need to provide inertia even in periods in which they are not generating.

Under a generator obligation, generators might not necessarily have to physically produce inertia themselves but might be permitted to meet their obligations by contracting with other providers (either synchronous generators or synchronous condensers). However, it would be important under such a scheme for AEMO to have visibility of how generators' obligations were being met or some procurer of last resort mechanism. That is to say that it would not be sufficient just to financially penalise non-compliance – the under-provision of inertia may need to be made good in order to maintain the secure operating state of the power system.

Box 3.3 An inertia credit scheme

The efficiency of a generator obligation might be enhanced if implemented through an inertia credit scheme. Under such a scheme, a baseline obligation would be derived (defined as MW.s of inertia required per MW of capacity dispatched) and applied to each generator.

Generators providing inertia above their baseline obligation would earn credits and be able to sell these. Operators of synchronous condensers could also create and sell credits. Generators providing less inertia than their baseline obligation would be required to purchase and surrender credits equal to the shortfall.

Such a scheme would raise a number of questions, including whether:

- The credits would have to be secured prior to dispatch, to give AEMO confidence that, in each dispatch interval, sufficient inertia will be provided.
- AEMO would require a mechanism to constrain certain synchronous units on where sufficient inertia was not procured by generators requiring inertia credits, either under a model where credit trades were notified to AEMO ahead of real time or surrendered subsequently.
- Non-compliant generators should be constrained-off or down in dispatch as a result of not securing inertia credits (although this would only be possible in a model where trades were notified to AEMO ahead of real time).

3.1.2 Inertia and fast frequency response as distinct services

The section above has focused on an obligation to provide a minimum level of inertia. However, an obligation to provide FFR services could also be imposed on generators. FFR could act as a substitute for the inertia that is provided, although only for inertia provided above the level required to maintain system stability.

The substitutability of inertia for FFR is the subject of ongoing investigations by AEMO. Nevertheless, there is sufficient information available to suggest that the substitutability is likely to vary based on a range of factors, including the level of inertia provided to the system, and the type of FFR services being provided.

There are various characteristics of FFR that would need to be taken into account in specifying an obligation, including the capability to provide both raise and lower services, the design of the control systems as either open-loop or closed-loop, allowance for energy recovery periods following the provision of FFR, and the ability to ride-through faults and maintain active power levels.

Nevertheless, there may be some benefit in requiring new non-synchronous generators to have some capability to provide FFR services. An obligation of this nature would increase the level of FFR available in the system and would provide a foundation to establish a competitive market for FFR services at some point in the future. It is likely there would be lead times in determining and setting obligations on generators, and to allow generators to prepare systems and/or build infrastructure to meet the obligation.

Box 3.4 Hydro-Québec[20]

A commonly cited example of an obligation to provide FFR is provided by Hydro-Québec TransÉnergie in Canada. The Québec system is synchronously isolated from other North American grids, although it is interconnected to the Eastern Interconnection with a HVDC link.

In 2006, Hydro-Québec introduced a requirement that new wind farms connecting to its network should provide FFR in order to emulate an inertial response. This specified that wind farms greater than 10MW must have the capability to "reduce large, short-duration frequency deviations at least as much as does the response of a conventional synchronous generator whose inertia constant equals 3.5s".

The requirement was introduced in response to projections that wind generation by 2015 would represent a penetration of 10% of peak load, and close to 25% at light load. Without the FFR, modelling suggested that, in the event of a contingency such as the loss of a large hydro generator, the resulting frequency nadir[21] might be low enough to trigger load shedding. The introduction of the FFR requirement was therefore intended to facilitate a similar frequency response to a system with all synchronous generators.

While this experience is useful in that it suggests that the mandatory FFR requirement on new wind generation has not halted investment, caution should be exercised in attempting to draw broader conclusions as the circumstances in the Québec system are quite different to the NEM. In particular, inertia remains relatively plentiful, with virtually all generation capacity other than wind turbines being hydro power. The concerns that led to the introduction of the FFR requirements implied a maximum RoCoF of only about 0.4Hz/s. More generally, the Québec system operates with quite different technical and commercial arrangements for frequency response as compared to the NEM.

20 Information in this section is drawn from: DGA Consulting, *International Review of Frequency Control Adaptation – Report for the Australian Energy Market Operator*, 14 October 2016, pp. 95-105.

21 The nadir is the lowest value of the frequency following a contingency prior to the frequency recovering to its normal value.

3.1.3 Location of the services in the network

Under a generator obligation, the locational deployment of inertia across the system would likely vary depending on the exact design. An obligation on each generator to physically provide inertia would result in broad geographical reach, although would risk overall over-provision. While an inertia credit scheme or contracting approach would allow a more efficient overall level of provision, it would be more difficult to target the location of the inertia without introducing onerous constraints. A requirement to contract inertia within each region might be a pragmatic approach, but still may not be granular enough to address system strength issues.

Synchronous devices that provide inertia to the system, such as synchronous generators and synchronous condensers, also increase the system strength in the area of the network in which they connect. As such, a generator contracting approach may poorly integrate with requirements to maintain system strength across the system. Non-synchronous generators might still need to physically provide inertia if connecting to a relatively weak area of the network.

Unlike inertia, fast frequency response technologies do not tend to contribute to system strength in the area of the network to which they connect. A requirement to maintain system strength in certain areas of the network might therefore limit the ability of non-synchronous generators to meet their obligations through the provision of FFR rather than inertia.

3.2 AEMO contracting

There may be potential for AEMO to procure inertia or FFR via a competitive tender process or bilaterally negotiated process.

A key input for this option is collaboration and consultation between AEMO and market participants or other potential service providers to ensure that AEMO possess all the necessary information to inform the design and implementation of this option. The level of involvement of different parties would need to be considered, including the relevant TNSP(s).

The development of an AEMO contracting option would require the establishment of a set of guidelines and procedures outlining the process for conducting an EOI or invitation to tender and the process for entering into contractual arrangements. Specifications of the service could also be outlined including a description of the proposed services, details of the facilities that may offer to deliver the service, levels of performance required, proposed charges, modelling data, testing evidence etc. It could also set out at a high level process for negotiating bilateral arrangements between AEMO and a provider, and any minimum terms and conditions that should be included in contracts.

AEMO would be required to work closely with NSPs and potential service providers to develop detailed system models and tools to analyse tender submissions. A range of factors would need to be considered, such as:

- the location of offered versus required inertia;
- potential impact on system strength at different locations;
- the risk of intra-regional separation; and
- contracting with generators with low RoCoF withstand capability.

The form and characteristics of AEMO contracts would also need to be carefully considered. The details of the provision of the service would need to be outlined in the contract, ie what are the availability obligations for the provider over the term, how will the service be dispatched and what other operational protocols need to be considered. Payments could be structured either as a fixed charge or a usage payment or both.

3.2.1 Providing the required level of system security services

A mechanism that involves contracting is likely to have benefits in being able to tailor the requirements for investor certainty with the flexibility to adapt to changing market conditions. Longer duration contracts with fixed payment structures may be used to meet the required operating level of inertia. Shorter duration contracts with more flexible payment structures may be used for inertia or FFR above the required operating level that provides market benefits.

AEMO would need to assess the best approach for providing investor certainty and flexibility through contract duration while providing sufficient levels of inertia. For example, if AEMO contracts were designed over the longer term at a potentially high capital cost, there is a risk that these assets would become stranded or significantly devalued when improved technologies were developed. There is also a risk associated with short term contracts, as they may not provide the required level of certainty for investment and result in a lack of incentives for the provision of inertia, particularly building physical infrastructure.

The breakdown of fixed or variable, availability and usage charges could be a useful mechanism to provide an optimal balance between certainty and flexibility depending on the conditions of the contract. This breakdown could also provide incentives for both existing and new entrants wanting to provide inertia to the market.

A balanced outcome between certainty and flexibility should be achievable if a flexible and adaptable mechanism is adopted. AEMO might be as well placed as any to assess how to achieve this balance and adjust its contracting accordingly. Of course, a potential downside is that AEMO may face limited incentives to minimise the costs of these contracts, which would be passed through to consumers.

3.2.2 Inertia and fast frequency response as distinct services

The early stage of FFR technologies and the limited use of FFR services in power system operation, particularly as a contingency service, suggest that contracts are likely to be the most appropriate mechanism with which to procure FFR services in the short to medium term.

Given the emerging nature of the FFR market and the possibilities around new technologies providing FFR into the future, AEMO contracting could act as a starting point for the development of a more competitive market. It could provide a balance between investor certainty, potentially reducing risk around investing in FFR services, and providing flexibility for market developments and emerging technologies.

AEMO contracting may be a suitable mechanism for new entrants to provide the service as it may reduce the risk associated with capital expenditure, while also providing incentives for new entrants to enhance their technologies and capabilities to provide lower cost FFR into the future. Pursuing this option would require consideration to be given as to how to give AEMO a clear objective and framework to use when undertaking assessments of competing offers of different time durations or prices structures. This is because allowing AEMO to acquire frequency services for market benefits across the NEM is potentially a broader role than its responsibility for delivering system security.

Box 3.5 National Grid (Great Britain)[22]

National Grid, the transmission network owner and operator in England and Wales, has developed a framework for procuring an enhanced frequency response (EFR) service through a contract tender process. Providers of the EFR service are required to respond to a frequency deviation with full active power delivery in one second or less. The active power delivery must then be sustained for a period of 15 minutes.

National Grid has contracted eight separate offers for a combined total of 200 MW of EFR service through a tender process that was conducted in July 2016. Contracts are to be commissioned in March 2018 for a four-year term. Payments under the contracts are based on service performance and availability. Each provider is capped at a total of 50 MW, although this is expected in increase in the future.

Insights from National Grid's experience in conducting the tender process and entering into contract arrangements could prove useful if a similar process was to be run by AEMO. However, it is worth noting that the EFR service is intended as a continuous control service aimed at maintaining system frequency close to 50 Hz under normal operation. It is not designed as a contingency service to arrest rapid changes in frequency following a system disturbance. The EFR service does not resemble the type of FFR service that is likely to be required to address the longer term system security issues in the NEM.

22 Information in this section is drawn from: DGA Consulting, *International Review of Frequency Control Adaptation – Report for the Australian Energy Market Operator*, 14 October 2016, pp. 126-129.

3.2.3 Location of the services in the network

If inertia were to be procured by AEMO through a contracting option then this would likely enhance the general levels of system strength. However, AEMO would have to consult closely with the NSPs when assessing tender submissions or negotiating contracts to ascertain the likely location of system strength issues. This may limit the number of potential providers of inertia if they were required to provide system strength at a specific location. Fewer providers of inertia that are able to participate in a competitive tender process may mean that AEMO is more reliant on bilateral negotiated contracts with individual providers.

3.3 TNSP solution

Inertia or FFR could be provided by the TNSP through either:

- directly investing and constructing the assets that are required to deliver the services; or
- via contracts with third-party providers, including network support agreements (NSA).

These activities would be identified in the TNSP's Annual Planning Report (APR) and could be undertaken to address requirements related to either system security or the improvement of power transfer capability in the network.

To the extent that the requirements are not addressed by the TNSP, the existing NSCAS framework also provides a means for AEMO to identify and address the requirements. NSCAS requirements are identified by AEMO as part of its National Transmission Network Development Plan (NTNDP) after taking into account all activities which have been identified by the TNSP in its APR. As such, NSCAS requirements represent a gap between the level of services that have been identified by AEMO and those that have been identified by the TNSP. This is referred to as the NSCAS Gap.

The TNSP's response to the identification of a NSCAS Gap can take the form of physically building assets or contracting a service to a third party. The TNSP determines the most economically efficient option for addressing the NSCAS Gap by comparing expressions of interest from third party providers.

If AEMO perceives that the TNSP has not responded adequately to address the NSCAS Gap, AEMO may act as the "procurer of last resort", however it can only acquire services to address system security or reliability NSCAS Gaps, not market benefits.

While the NSCAS framework is potentially available in its current form to provide a solution, the identification of a NSCAS Gap relies on the cycles of AEMO's NTNDP and the TNSP's APR. Further, a Regulatory Investment Test for Transmission (RIT-T) process, if needed, may be quite involved and will take time to undertake. Alternatively, a NSA can be initiated at any point in time.

For the purpose of considering this mechanism, the NSCAS framework could be incorporated with an AEMO contracting solution. Procedures for how such an incorporated process would operate would need to be developed.

3.3.1 Providing the required level of system security services

A TNSP contracts-based solution is likely to draw the right balance between being able to tailor the requirements for investor certainty with the flexibility to adapt to changing market conditions.

Activities identified by the TNSP could be undertaken to address requirements related to either system security or the improvement of power transfer capability in the network, and as such may be able to provide the required operating levels of inertia and also additional inertia or FFR where an economic benefit can be identified.

The NSCAS framework also provides a potential means to deliver inertia and FFR. The NSCAS framework is defined in the NER as a service with the capability to control both active and reactive power flow into and out of a transmission network to either:

(a) maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard; or

(b) maintain or increase the power transfer capability of that transmission network so as to maximise the present value of net economic benefit to all those who produce, consumer or transport electricity in the market.

This suggests that the NSCAS framework may be broad enough to capture both the required operating level of inertia to maintain system security as well as the levels of inertia and FFR that could be provided to alleviate network constraints and increase economic efficiency.

As with the AEMO contracting option, NSP contracting is likely to have benefits in being able to tailor the requirements for investor certainty with the flexibility to adapt to changing market conditions.

However, a benefit of the NSP contracting option over the AEMO contracting option is that the current rules require the TNSP to assess the least cost approach to addressing the issues through the RIT-T framework. Any obligation to contract on AEMO would need to be accompanied by principles to guide the contracting process and drive towards a least cost outcome in the long term interests of consumers.

Box 3.6 The Regulatory Investment Test for Transmission

The Regulatory Investment Test for Transmission is an economic cost benefit analysis which is used to assess and rank different investment options for transmission networks.

Under the RIT-T, a detailed cost-benefit analysis is undertaken to identify the investment option which has the highest net benefits. The net economic benefit of a credible option is the expected market benefit less the expected costs of the option. The credible option with the highest expected net economic benefit would be the option pursued first. Other options would subsequently be pursued in descending order of expected economic benefit.

Currently, a RIT-T is applied for all augmentation investments greater than six million dollars. For investments under the six million dollar threshold, the TNSP has discretion to determine the most appropriate assessment.

TNSPs are required to consider all feasible network and non-network options. TNSPs are required to seek submissions from registered participants, AEMO and interested parties on the credible options considered as part of their investment test.

Investments with negative net economic benefits are permitted under the RIT-T framework if the investment is undertaken to meet a reliability, system security or technical standards requirement. However, it must still be demonstrated that the investment is the least cost approach.

3.3.2 Inertia and fast frequency response as distinct services

It appears likely that the provision of FFR services could be undertaken by NSPs to manage system security or improve power transfer capability.

The early stage of FFR technologies and the limited use of FFR services in power system operation, particularly as a contingency service, suggest that contracts are likely to be the most appropriate mechanism with which to procure FFR services in the short to medium term.

However, there is a possibility that the construction of physical assets by the TNSP would tend to focus on proven technologies such as synchronous condensers providing inertia. This may risk locking out FFR technologies that are in the early stages of development but which may present lower cost options to manage system frequency in the future.

3.3.3 Location of the services in the network

When contracting for the provision of inertia, the TNSP will necessarily need to assess the location of the new synchronous devices in order to determine the impacts on system strength. These synchronous devices will also have an impact on the control of system frequency and may either partially or fully address the required operating level of inertia needed to maintain system security.

Allocating the responsibility to the TNSP to contract for the provision of inertia would be more likely to avoid the possibility of higher costs that would be incurred through the duplication of network assets. For example, the TNSP would be in a better position to identify that the construction of a single synchronous condenser would be a more cost effective approach to the simultaneous management of both frequency and system strength. There is a greater likelihood that separate assets would be constructed to address frequency and system strength individually if separate entities were given responsibility or separate mechanisms were used.

The requirement for the operating level of inertia to be available at all times and the necessary involvement of the TNSP would appear to strongly support the option to obtain this level of inertia through a NSP contracting approach.

3.4 Market sourcing

A market solution to sourcing inertia would involve:

- incorporation of the inertia in the dispatch process with a price paid to providers based on the value of the service; or
- a separate dispatch process with offers submitted by providers of the inertia and a price determined on the basis of those offers.

A critical market design issue is the timeframe over which offers are made and dispatch occurs. While multiple options are possible, the two most obvious timeframes are:

- adoption of the five-minute dispatch and settlement periods used for the existing contingency FCAS markets;
- adoption of a longer lead timeframe such as a day-ahead framework consistent with AEMO's pre-dispatch.

3.4.1 Providing the required level of system security services

A market sourcing approach could be used to provide the required operating levels of inertia and also additional inertia or FFR where an economic benefit can be identified.

A market sourcing option for inertia potentially offers significant flexibility to vary the required level of the service over time to adapt to changing market conditions. This is similar to the flexibility provided by the NEM. The NEM design promotes economic efficiency in dispatch through the determination of generator output on a five-minute basis in accordance with maximising the value of trade. Flexibility in adjusting to changing market conditions is achieved through the ability of generators to rebid their offered generation capacity between price bands.

Investment certainty in the NEM is underpinned by a separate secondary contract market which permits market participants to obtain a fixed price for the provision of energy generally up to four years ahead. The liquidity in the secondary contract market is facilitated by the presence of multiple potential trading counterparties and the settlement of energy payments limited to five regional prices.

Without a liquid secondary contract market for inertia, the incorporation of inertia services into the existing wholesale energy spot market framework is unlikely to provide the necessary levels of certainty to prospective investors. This is particularly relevant for the required operating level of inertia, which must be provided at all times.

Beyond the required operating level of inertia, a market sourcing approach may have advantages over other mechanisms through the ability to adapt in real time to changing market conditions and co-optimise the provision of inertia with FFR and constraining the system to achieve an economically efficient outcome. However, the physical characteristics of the supply of inertia may present a number of issues which may inhibit the effective integration of inertia into the existing wholesale energy market dispatch process.

For any five-minute dispatch interval, the level of inertia in the system is currently dependent on the combination of synchronous generators that are online at the time. Generators provide all of their inertia when they are online or no inertia when they are offline, regardless of energy output. Therefore, any increase in the level of inertia would require the start-up of an additional generating unit. This is different to energy where an incremental increase in the demand for energy can generally be accommodated by an incremental increase in the output of the generating units that are already online. As such, the provision of inertia through a five-minute dispatch model may require generators to be notified well in advance of the relevant dispatch interval, such as through a day-ahead dispatch model.

The relative inflexibility of existing thermal generating plant in terms of start times suggests that care will need to be taken in any market design in order to minimise the ability of generators providing inertia to influence energy price outcomes.

These issues may not be insurmountable but may require a substantial redesign of the existing wholesale energy market dispatch process and bidding framework, which would likely mean a longer lead time for implementation.

3.4.2 Inertia and fast frequency response as distinct services

A number of the issues associated with integrating the provision of inertia into the wholesale energy dispatch process are unlikely to apply to the provision of FFR. FFR would not face the same unit commitment times as synchronous generating units that provide inertia. As such, FFR services are likely to be able to be co-optimised with the provision of energy through the existing energy market dispatch process, similar to the existing markets for FCAS. Indeed, if a separate market for FFR were to be developed, it is possible that it may be an additional form of FCAS with a one second specification, including separate raise and lower services that are dispatched on a five-minute basis.

A FFR service is likely to substitute for inertia to some extent. The target FFR quantity will be related to the level of inertia available at any point in time and the contingency size that is sought to be protected against. Real time optimisation of FFR quantity consistent with system security requirements and interaction with inertia (and ideally system strength) will require development of suitable models and clear definition of the nature of the FFR service.

The principal issue with implementing new markets for the provision of FFR services at this time is the lack of existing providers of FFR services, the fledgling state of the technologies that provide such services, and the lack of experience and understanding as to how the operation of the power system might be impacted. Many FFR technologies are in the early stages of development with limited examples of FFR currently being actively used to manage power system operations in overseas jurisdictions, particularly with respect to responding to contingency events.

A greater level of experience with using FFR services to control system frequency may be required before a service could be properly specified and a 5-minute market developed that would be able to be co-optimised efficiently with the existing energy and FCAS markets.

3.4.3 Location of the services in the network

The effective integration of inertia into the existing wholesale energy market dispatch process would likely require the inertia to be priced on the same regional reference basis as is undertaken for the pricing of energy. A regional price for inertia is unlikely to adequately signal the need to address low system strength in specific network locations. This argument can equally be applied to the management of system frequency and the possibility of intra-regional islanding.

FFR may be able to be supplied from across the NEM although in many instances where the contingency is related to interconnector flows then FFR will need to be supplied from within a geographic region. This may be further complicated by the interaction with system strength where there may be a need for consideration of intra-regional issues and potentially local sourcing of FFR.

4 Proposed approach to procuring inertia and fast frequency response services

Box 4.1 Summary

As reflected in chapter 3, there is no one mechanism that provides the most effective solution for procuring inertia and FFR services, each having different advantages, some being better suited to procuring either inertia or FFR and others being easier to implement in the shorter term. The Commission is therefore proposing that a combination of complementary mechanisms be used to provide inertia and FFR services. These mechanisms are to be applied in two stages:

Immediate package - *to apply immediately*

- *Required operating levels of inertia* - TNSPs would be required to provide and maintain a defined operating level of inertia at all times. This required operating level of inertia would be determined by AEMO through a process prescribed in the NER. The required operating level would represent a workable level of inertia that would satisfy a range of, but not all, system conditions.
- *TNSP procurement of FFR* - As an interim measure TNSPs will be able to contract with third party providers of FFR services to meet their obligation to provide the required operating level of inertia where AEMO has permitted the FFR to substitute for part of the required operating level of inertia. TNSPs would have a window of three years to enter into contracts with third party providers. These contracts would provide a means for the development and trialling of FFR technologies.
- *Generator obligations for FFR capability* - Non-synchronous generators would be obliged to have the capability to provide FFR services. Generators would not be mandated to provide the service but would be required to install the capability for providing the service at the time of construction. The exact specification of the capability of the FFR service would likely depend upon the type of technology.

Subsequent package - *to apply after 3 years*

- *TNSP incentive framework to guide investments in inertia* - For additional inertia provided by the TNSP above the required operating level, an incentive framework would be developed to guide the TNSP's investment towards the most efficient approach. Under the incentive framework, TNSPs would be rewarded for the delivery of market benefits from a project to provide additional inertia that allowed for greater power transfer capability in the network.

The interim TNSP procuring of FFR services would be replaced by:

- *Market sourcing approach for FFR* - A market for the provision of FFR services would be established to optimise the FFR quantity consistent with system security requirements and levels of system inertia and other FCAS.

The balance of the immediate package will continue in this time period.

This chapter sets out the Commission's proposed approach to procuring inertia and FFR services. Mechanisms to be implemented as an immediate package of measures are outlined first followed by a discussion of a proposed subsequent package of measures.

4.1 Overview of the Commission's staged approach

In developing a staged approach, the Commission sought to strike a balance between addressing immediate issues related to the management of power system security and developing an efficient and effective framework to address such issues in the medium to longer term. A staged approach not only provides for immediate, practical solutions to key security issues but provides a transition pathway for establishing markets for evolving technologies that can provide frequency services.

4.1.1 Flexibility and investment certainty in the provision of inertia and FFR services

Achieving a secure operating system in an economically efficient manner requires market frameworks to be designed to encourage investment in system security services and to maximise flexibility in the provision of those services to achieve an economically efficient outcome.

The NEM design promotes economic efficiency in dispatch through the determination of generator output on a five-minute basis in accordance with maximising the value of trade. Flexibility in adjusting to changing market conditions is achieved through the ability of generators to rebid their offered generation capacity between price bands. Investment certainty is underpinned by a separate secondary contract market which permits market participants to obtain a fixed price for the provision of energy up to four years ahead.[23]

A similar market sourcing approach to inertia and FFR would also offer significant flexibility to vary the required levels of the services over time to adapt to changing market conditions. This would provide for more effective price discovery through the co-optimisation of inertia with FFR services and constraining the system to achieve an economically efficient outcome.

23 Four years reflects the extent of the forward curve in most ASX and OTC electricity contracts. However, there are no restrictions on the duration of contracts between counterparties.

The Commission considers that the development of a market sourcing mechanism is likely to be the preferred long-term approach to providing inertia and FFR services for system security purposes. However, there are a number of reasons as to why a market sourcing approach would not be a practical option in the short term. There are two principal issues with introducing a market sourcing approach for inertia.

- There are no natural counterparties for the provision of inertia. The demand for inertia arises as a consequence of a need to manage system frequency and maintain the secure operation of the system for the benefit of all participants. The development of a liquid secondary contract market for inertia would require the presence of counterparties on both sides of the transaction. Without a liquid secondary contract market for inertia, the incorporation of inertia services into the existing wholesale energy spot market framework is unlikely to provide the necessary levels of certainty to prospective investors. This is particularly relevant for the required operating level of inertia, which must be provided at all times.
- The provision of inertia through a market sourcing approach may require generators to be notified well in advance of the relevant dispatch interval, such as through day-ahead unit commitment. The relative inflexibility of existing thermal generating plant, in terms of start times, suggests that care would need to be taken in any modifications to the existing bidding and dispatch framework. The ability of generators providing inertia to influence energy price outcomes through rebidding may need to be managed, including possible restrictions on the ability of generators providing inertia to set the spot market price.

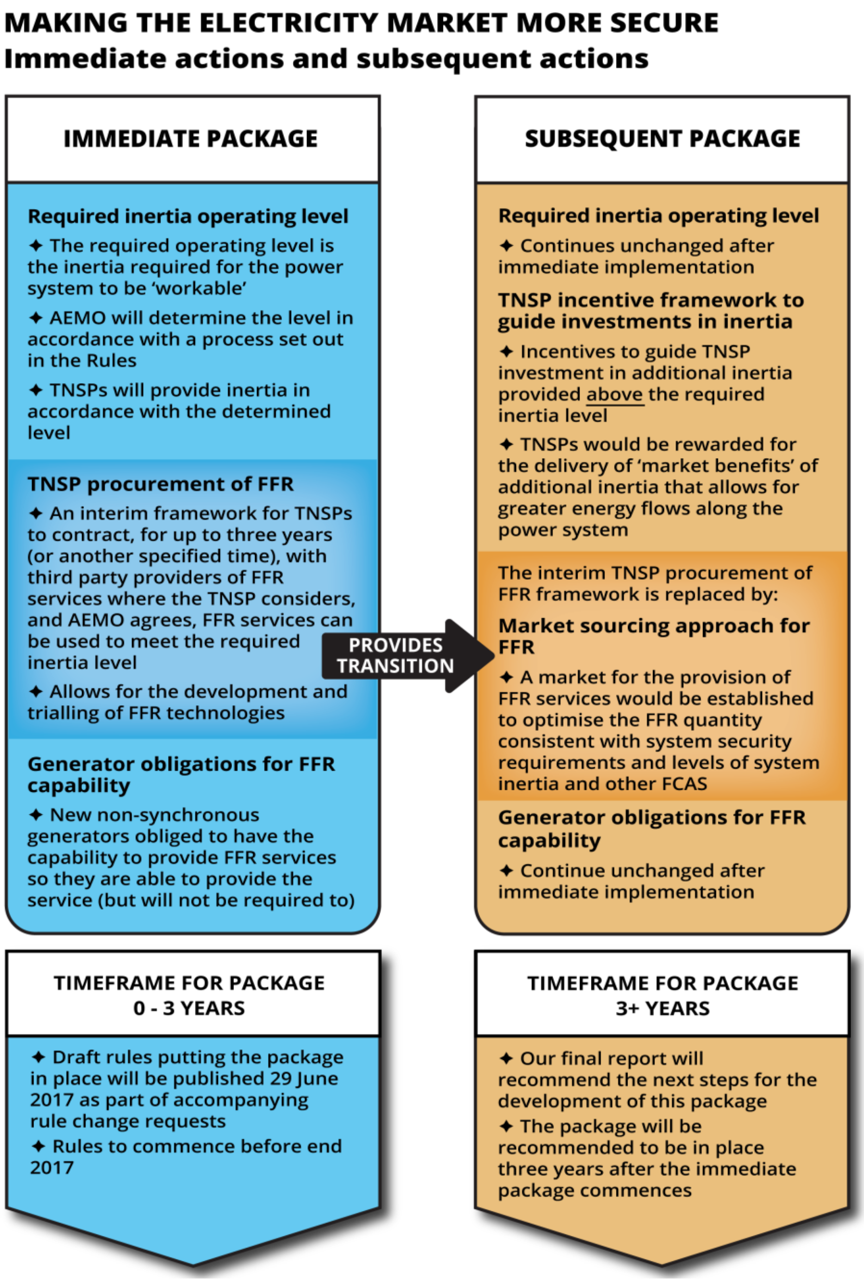
These issues associated with integrating the provision of inertia into the wholesale energy market dispatch process are unlikely to apply to the provision of FFR. FFR would not face the same unit commitment times as synchronous generating units that provide inertia. Technologies that provide FFR services are also likely to be providing these services as a by-product of the provision of other services, including energy. As such, they are unlikely to be reliant on payments for FFR as their principal source of revenue and, at least as a mature technology, would not necessarily require the revenue certainty provided by a specific contract for the provision of FFR services.

However, the principal issues with implementing a market sourcing approach for the provision of FFR at this time are the lack of existing providers of FFR services, the fledgling state of the technologies that provide such services, and the lack of experience and understanding as to how the operation of the power system might be impacted through the use of such services. Many FFR technologies are in the early stages of development with limited examples of FFR currently being actively used to manage power system operations in overseas jurisdictions, particularly with respect to responding to contingency events.

A greater level of experience with using FFR services to control system frequency is likely to be required before a service could be properly specified such that a market can be developed for the delivery of a homogenous FFR service that is able to be co-optimised efficiently with the existing energy and FCAS markets.

4.1.2 A two part framework for the provision of inertia and FFR

The Commission proposes that the provision of inertia and FFR be through a staged implementation of two packages of complementary measures as illustrated below. The first package would be implemented to address the more immediate issues related to power system security. The second package would be subsequently implemented to enhance elements of the immediate package.



A TNSP procurement framework

The Commission considers that the existing economic regulatory framework for TNSPs provides a basis to design a framework through which inertia could be obtained to address power system security issues, both immediately and over the long term. The provision of inertia by the TNSP is likely to provide benefits over other approaches for the following reasons.

- Achieving a secure operating system in an economically efficient manner requires market frameworks to be designed to encourage investment in system security services and to maximise flexibility in the provision of those services to achieve an economically efficient outcome. A contracts-based solution undertaken by the TNSP is likely to draw the right balance between being able to tailor the requirements for investor certainty with the flexibility to adapt over time to changing market conditions.
- The proposed TNSP procurement framework would be designed to capture both the required operating level of inertia as well as the levels of inertia that could provide market benefit by alleviating network constraints and increasing economic efficiency. The existing economic regulatory framework for TNSPs provides a foundation for the development of a process to efficiently procure inertia services based on economic benefits and to provide a degree of confidence in the availability of those services over time.
- The TNSP will necessarily need to be involved in assessing the location of new synchronous devices providing inertia in order to determine the impacts on system strength. Providing a framework for the TNSP to coordinate the requirements for frequency control with system strength will assist in reducing the potential for the duplication of assets providing similar services.

The Commission considers that the procurement of inertia services by TNSPs represents a practical and effective approach to the management of system frequency issues. The procurement framework for the services would utilise the existing economic regulatory framework for network businesses. However, new measures are necessary to improve the efficiency of the procurement of inertia while also providing a high degree of confidence that the required levels of inertia will be provided in order to maintain a secure power system.

Inertia would be provided by TNSPs through the following mechanisms:

- **Required operating level -** TNSPs would be required to provide and maintain a defined operating level of inertia at all times. This required operating level of inertia would be determined through a prescribed process conducted by AEMO. The required operating level would represent a workable level of inertia that is sufficient to satisfy a range of, but not all, system conditions. Obligating TNSPs to provide a required level of inertia provides a more immediate solution then pursuing a similar outcome through the existing NSCAS framework discussed in section 3.3.1.
- **Incentive framework -** TNSPs would also be permitted to identify and pursue opportunities to procure additional inertia beyond the required operating level where it results in net economic benefits through the alleviation of network constraints and improvements in the power transfer capability of the network.

An incentive framework would be developed to guide TNSP investments towards the most efficient approach.

However, the above approach may require a staged introduction. An obligation on TNSPs to provide a required level of inertia at all times is an effective and relatively straight forward approach to the provision of inertia. It would provide a high degree of confidence that the secure operation of the power system could be managed under a range of system conditions. Therefore we consider that requiring TNSPs to meet a defined operating level of inertia could form part of an immediate package of measures to address system security issues.

While forming part of an ultimate framework for the management of system security, the introduction of an incentive framework on TNSPs may be premature at this time. As previously discussed, FFR technologies represent a significant and potentially lower cost alternative to the provision of inertia. However, these technologies are at an early stage of development, both with respect to their use in power system operations, and as a contingency service to maintain system frequency following major disturbances.

The use of frequency control services is a well-established component of the secure operation of the power system. However, many frequency control services, particularly those that can operate in timeframes of less than one second, are unproven in the Australian context. Arguably, FFR services are not yet technologies readily accommodated by an economic regulation regime designed to consider the prudent level of spending on mature and long-lived assets.

It is likely that the construction of physical assets by the TNSP under an incentive framework would tend to focus on proven technologies such as synchronous condensers providing inertia. This may risk locking out FFR technologies that are in the early stages of development but which may present lower cost options to manage system frequency in the future. Equally, there is a risk that assets constructed now could become stranded or significantly devalued when improved technologies are developed. For these reasons, the Commission considers that implementing an incentive framework for TNSP provision of FFR services is more appropriately considered as part of a subsequent package.

TNSP procurement and generator obligations to transition to a market for FFR services

TNSP procurement of FFR services

The Commission also proposes TNSPs be allowed to identify and pursue opportunities to procure FFR services. Projects for the procurement of FFR services by the TNSP would be permitted as a substitute for part of the obligation to provide the required operating level of inertia if approved by AEMO. AEMO would assess whether, and to what extent, the FFR delivered by the project could substitute for the delivery of inertia. This would be undertaken on a case-by-case basis in order to account for the varying characteristics of FFR services provided by different technologies to ensure that the inertia needs of the power system are not compromised by the use of the proposed FFR.

Without the abovementioned complementary incentive framework for TNSPs, and a market sourcing approach for FFR, obliging TNSPs to meet defined operating levels of inertia as the only measure to address system security issues would mean that there would be no immediate mechanism in place for the provision of FFR technologies in the short term.

Therefore, the Commission proposes to allow TNSPs to contract with third party providers of FFR services, with AEMO approval, as an interim measure.

The early stage of FFR technologies and the limited use of FFR services in power system operation, specifically as a contingency service, suggest that contracts are likely to be the most appropriate mechanism with which to procure FFR services in the short to medium term. In order to further develop these technologies and gain experience in their use in power system operations, the Commission considers that allowing for the trialling of technologies will be beneficial.

The window of time during which contracts could be entered into would be limited to three years. The Commission does not propose to apply a limit on the duration of contracts. However, the intention of this part of the package is to provide a transition pathway to the market sourcing approach as part of the subsequent package.

Once the market sourcing approach has been implemented, the provision of FFR services already procured by the TNSP would remain under contract. Any new projects for the delivery of FFR services would participate in the market.

The Commission understands that there are various technologies that have the potential to provide FFR and that FFR may be only one of the value streams being provided by such technologies (eg storage systems). TNSPs will continue to be able to procure network support services from providers of such technologies. However, funding under contracts with TNSPs will only be provided to the extent the services being acquired are FFR services for the purpose of meeting the required operating level of inertia.

The form and characteristics of TNSP contracts would need careful consideration. The details of the provision of the inertia or FFR services would need to be outlined in the contract, including the availability obligations for the provider over the term, conditions under which the service will be dispatched, and other operational protocols that need to be considered.

AEMO would need to be involved in defining the conditions under which the service is enabled and utilised. The availability and provision of the FFR service would need to be factored into the formulation of constraints for power system operation.

AEMO's primary role in the oversight of power system operations suggests that it would be well placed to coordinate with the TNSP to engage in the trialling of FFR technologies and how such technologies can be integrated into the management of system security.[24] Trialling of these technologies should also provide higher levels of investor confidence and provide a more robust foundation as an established and proven technology for future third party investments.

Allowing for TNSPs to acquire FFR services as part of meeting the required operating level of inertia provides an avenue for the growth and development of FFR technologies and also provides a means by which AEMO could develop specifications in relation to the service. This should allow for a more efficient transition to a market sourcing approach for the provision of FFR services.

Generator obligation

The Commission considers there may also be some benefit in requiring new non-synchronous generators to have the capability to provide FFR services. Many new non-synchronous forms of generation are manufactured with the capability to provide a fast response to frequency deviations. It is likely that an obligation on non-synchronous generators to provide some form of FFR capability would not be an onerous requirement and would likely result in a number of long-term benefits. An obligation of this nature would increase the level of FFR available in the system and would provide a foundation to establish a competitive market for FFR services at some point in the future.

4.2 Immediate package

This section sets out, at a high level, the nature of the Commission's proposed changes to address the more immediate issues related to power system security.

4.2.1 Required operating levels of inertia to be provided by TNSPs

TNSPs would be obliged to provide and maintain a required operating level of inertia. This required level of inertia would be considered to be optimal under a range of, but not all, system conditions.

The required operating level of inertia would be determined periodically through a prescribed process developed by AEMO. Specific requirements in relation to the content and development of the prescribed process would be set out in the NER and would include the range of system conditions which the required operating level must meet. The required operating levels of inertia would be set out as part of the NTNDP.

As part of the process, a number of defined network areas would also be determined. The level of system inertia that would be required to maintain secure operation of the network area as an islanded system will be determined. Defined network areas may consist of single NEM regions or sub-regions.

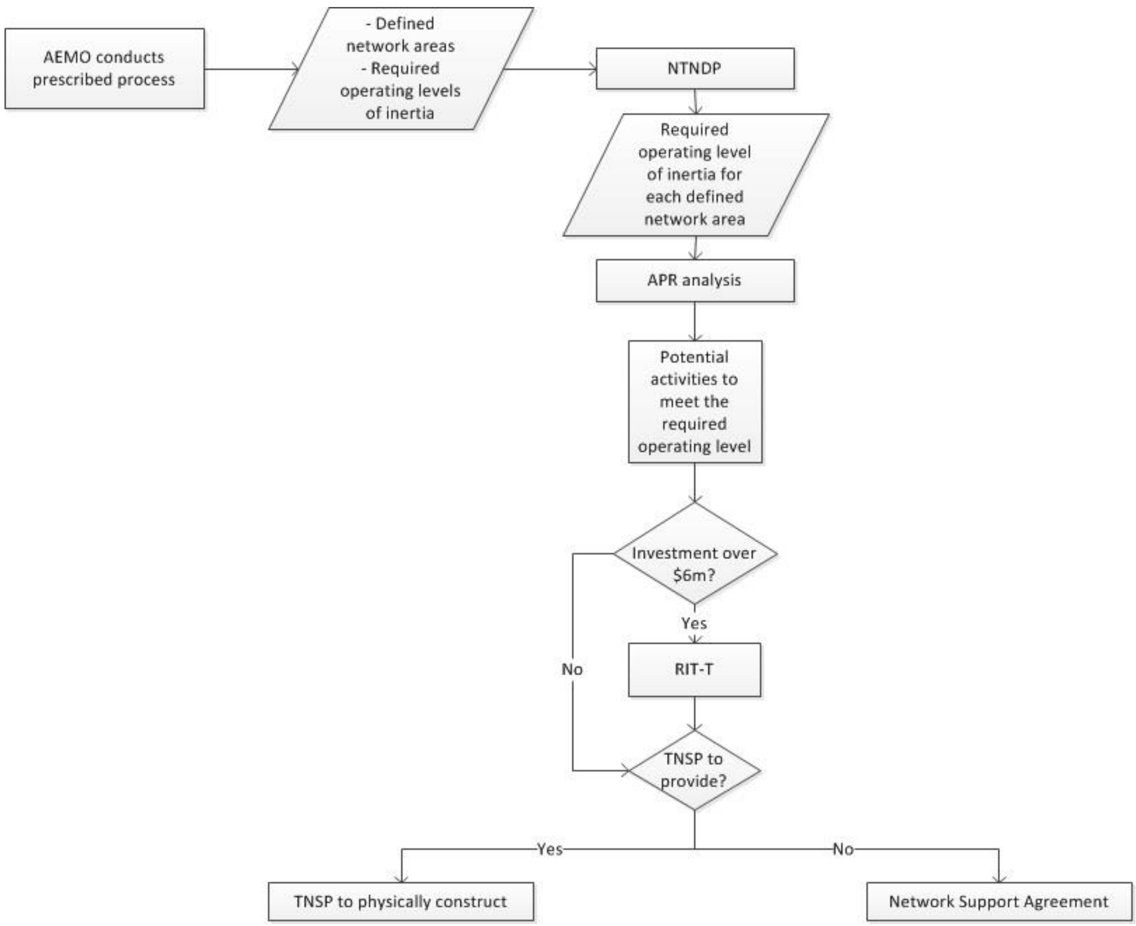
24 AEMO, Submission on the interim report, p. 4. AEMO suggests that a series of trials could be used to establish the technical capabilities and benefits of FFR delivery

TNSPs would be obliged to meet the required operating level for each defined network area. The TNSP's proposal to meet the required operating level of inertia would be developed and set out as part of its APR.

Meeting the required operating level of inertia could take the form of physically building assets or contracting services from third parties. The TNSP would determine the most economically efficient option for meeting the required operating inertia level by undertaking a RIT-T to compare offers from third party providers against the option of physically constructing the required assets.

Figure 4.1 below sets out the components involved in determining the required operating level of inertia and how the TNSPs would then go about meeting them.

Figure 4.1 TNSP provision of the required operating level of inertia



Determining the defined network areas

As part of the prescribed process AEMO would determine separate required operating levels of inertia for each defined network area to operate as an island should it be separated from the rest of the NEM.

The NEM mainland and Tasmania operate as two separate synchronous systems. The two systems are separated by the Basslink DC interconnector which allows for energy transfer but does not require the two systems to operate synchronously. In order for

Tasmania to operate as an island, inertia must be sourced locally. This would imply that a separate operating level of inertia would be required for Tasmania.

This principle can also be applied to other areas of the NEM where there is a possibility of separation and islanding. For example, the separation of South Australia from the rest of the NEM, caused by the unavailability or failure of the Heywood Interconnector, would require South Australia to source inertia locally to operate as an island and maintain system security.

Each area of the national network that is required to be able to operate independently as an island would source inertia locally up to its required operating level. For each network area there would need to be a possibility of separation and a realistic prospect of continued operation after separation. While a comprehensive list of these areas would need to be developed, it is expected that separate operating levels of inertia would need to be determined for Tasmania, South Australia, New South Wales and Victoria combined,[25] North Queensland, and South Queensland.

The process for determining the defined network areas could potentially be similar in concept to the process used by AEMO for defining the electrical sub-networks for the system restart standard. Electrical sub-network boundaries under the system restart standard reflect factors including the concentration of load and generation as well as the structure of the network. AEMO is required to consult on the establishment of these boundaries and to publish a report setting out how it has complied with the requirements of the system restart standard in accordance with the rules consultation procedures.

Determining the required operating level of inertia

AEMO would determine the required operating level of inertia in accordance with a prescribed process set out in the NER. The NER would set out the content for and assumptions to be taken into account in such determinations.

The required operating level of inertia would represent a workable level of inertia that would satisfy a range of, but not all, system conditions. This means that the process would determine a level of inertia that is higher than the absolute minimum system threshold and would therefore also provide some market benefits.

The level of inertia that is provided to the power system can have a significant impact on the size of potential contingencies and the capability of the power system to transfer electricity from generation sources to load centres. The economic implications of determining the required operating level of inertia are significant. While AEMO is best placed to be determining the required operating level, given the economic trade-off involved, the Commission considers it would be appropriate to prescribe, in the NER, the factors and assumptions AEMO should take into account. This will also insist in establishing a transparent and objective process.

25 The probability of a separation between New South Wales and Victoria is considered to be low, although Victoria ran as an island for a period on 16 January 2007.

What is involved in determining the required operating level of inertia?

It is expected that under the prescribed process AEMO would model a range of scenarios representing different combinations of generator dispatch patterns and system and network conditions. Under each scenario, the size of potential contingency events and the tolerance of the system to RoCoF would determine the required level of inertia to maintain a secure operating system.

An operating level of inertia would be determined based on the levels of inertia required under each of the modelled scenarios. The required operating level of inertia would not be equal to the level of inertia needed under all scenarios. Instead, the prescribed process would define a pre-determined proportion of the scenarios for which the required operating level of inertia would be sufficient to maintain a secure operating system. For example, the proportion of the scenarios could be equal to 90-95% of those modelled. The exact proportion of the scenarios would be pre-determined and would be set out in the NER as part of the methodology for developing and conducting the prescribed process.

A number of scenarios related to protected events would also be modelled by AEMO. The levels of inertia required to maintain secure operation of the system under these scenarios would also be used to determine the required operating levels of inertia.

Managing a secure system with the required operating level of inertia

The required operating level of inertia would be determined on the basis of satisfying a proportion (possibly 90-95%) of the scenarios modelled by AEMO. This means that there will be some possible system conditions where the required operating level of inertia would not be sufficient to maintain a secure operating system should a contingency occur. In these instances, AEMO would maintain a secure operating system through the application of constraints in dispatch. AEMO's determination on the necessity and extent of applying constraints on dispatch will depend on the tolerance of the system to RoCoF.

Permitting AEMO to vary operational arrangements for the management of system security may be more optimal as the tolerance of the system to RoCoF varies under different system conditions. For example, the limit on RoCoF at any particular point in time is likely to be principally determined by the generating unit with the lowest withstand capability. If that particular generating unit has a much lower withstand capability than other generating units, then the RoCoF limit is likely to be much higher, and consequently the level of required inertia lower, in circumstances when it is not online.

Factors AEMO would be required to take into account in determining the required operating level of inertia

For each of the modelled scenarios considered by AEMO, a range of factors are likely to influence the required level of inertia in a region, including:

- the capacity and number of generating units and transmission lines in the region which would establish the size of potential contingency events;
- the tolerance of generating units in the region to different RoCoF levels; and
- the availability of other frequency control services.

The impact of these three factors on the level of required inertia is expressed through the following equation:

$$I = (25 \times \Delta P)/RoCoF'$$

Where

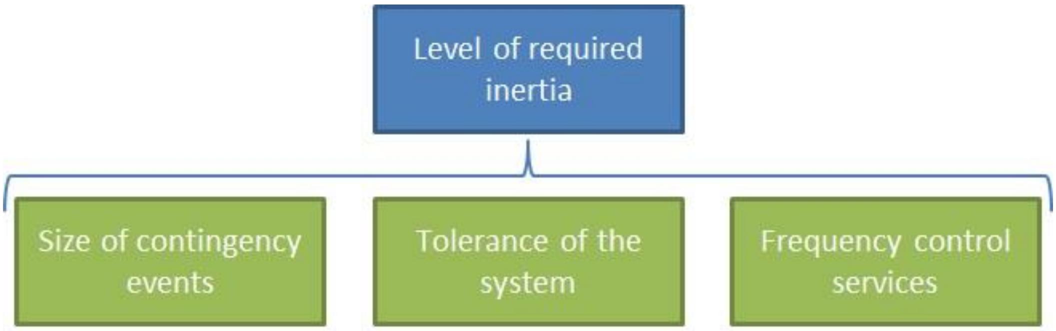
I = The level of required inertia (MW.seconds)

ΔP = The size of the contingency (MW)

RoCoF′ = the rate of frequency change that would cause the generator with the lowest withstand capability to trip (Hz/second)

The level of required inertia is proportional to the size of the largest contingency and inversely proportional to the RoCoF withstand capability of generators. Fast response services, such as FFR and direct communications emergency protection schemes, can also reduce the required level of inertia by reducing the effective size of the contingency.

Figure 4.2 Factors that affect the required level of inertia



Size of contingency events

The level of inertia required to limit RoCoF is proportional to the size of the contingency event. The larger the contingency event, the more inertia is required to limit the level of the RoCoF.

As an example, a large contingency event such as a failure of the Heywood Interconnector between South Australia and Victoria at a time of high power transfer would result in a high rate of change of frequency. The rate of change of frequency would be even higher if there are only a few synchronous generating units contributing inertia in South Australia at the time of the contingency.

Within any given region, there are a range of potential contingency events that could occur, each of different size and probability of occurrence. The process required to determine the required operating level of inertia would necessarily involve an assessment of the capacity and operating patterns of different generators, as well as the potential likely combinations of generating units dispatched at different times.

Contingency events generally consist of large generating units or transmission lines that suddenly stop producing or transmitting electricity, or large industrial facilities that suddenly stop consuming. The Energy Networks Association (ENA) and Energy Queensland note the importance of the future integration of distributed energy resources in the NEM.[26] The ENA suggests that, in the future, switching of aggregated distributed energy resources in the distribution system may exceed the capacity of individual generating units, substantially impacting system frequency.[27] TasNetworks also highlights that the energy deficiency created at the initiation of system events due to the fault ride-through response of inverter based equipment can be significant, and should also be considered in determining required levels of inertia.[28]

Tolerance of the system

The capability of generators within a region to withstand high RoCoF will influence the level of inertia required to maintain system security. A number of stakeholders highlight the importance of identifying the RoCoF withstand capability of generating units to determine the required levels of inertia to maintain a secure operating system.[29]

Generators that trip as a consequence of high RoCoF may exacerbate the disturbance to the system and lead to an even higher RoCoF by both contributing to the overall size of the contingency as well as reducing the level of inertia in the system.

The level of RoCoF that the system can withstand depends on the capabilities of the generating units that are online at the time of the contingency event. A single, large unit that cannot tolerate the conditions following a disturbance may act as a 'weak link'. This has the potential to significantly impact the level of inertia required to maintain a secure operating system.

This is complicated by the fact that the RoCoF tolerance of most units in the NEM is unknown. The generator performance standards in relation to withstanding rates of change of system frequency are set out in schedule 5.2.5.3 of the NER. However, these standards have only been imposed as a condition of generator connection agreements since 2007.

26 See submissions on the interim report from: ENA, p. 5; Energy Queensland, p. 2.

27 ENA, Submission on the interim report, p. 5.

28 TasNetworks, Submission on the interim report, pp. 1-2.

29 See submissions on the interim report from: ENA, p. 3; EnergyAustralia, pp. 2-3; Delta Electricity, p. 3.

While historical incidents can provide some indication of the withstand capability of older generators, the capability of any particular generator to withstand high RoCoF is largely dependent on the operating and market conditions present at the time of the event, including:

- the output of the generator immediately prior to the contingency (a generator at full output is more likely to trip for a given RoCoF);
- the inertia provided by the generator (a generator providing high inertia would have lower withstand capability);
- the strength of the system (at low fault level, generators are more likely to trip for a given RoCoF);
- the length of the RoCoF period (a longer period is more likely to cause a generator to trip); and
- whether the RoCoF is positive or negative.

In order to allow for variable system conditions and the unknown, but potentially limited, RoCoF withstand capability of some generating units, the prescribed process may need to incorporate an additional margin of inertia when determining the required operating level.

ENA, Delta Electricity and TasNetworks all emphasise the importance of taking into account the RoCoF withstand capability of the specific generators that are providing inertia.[30] The required operating level of inertia would also need to account for the fact that the contingency that occurs may be the loss of a large synchronous generating unit providing inertia. Disconnection of synchronous generators may further increase the RoCoF (for under-frequency events) and make it more difficult for the remaining generators to stay connected, particularly in cases where the generators that disconnect first are contributing to system inertia. In this manner, a system disturbance that results in a high negative RoCoF could very quickly result in cascading tripping of generators.

Availability of frequency control services

Contingency FCAS is coordinated locally by generators in response to larger frequency deviations that occur following contingency events. These local technologies are designed to detect and respond to frequency deviations and include generator governor responses, load shedding, rapid generation response, and rapid unit unloading.

The fastest contingency FCAS operates over a six-second timeframe. Technologies providing this service are required to provide peak output at the six-second mark but may commence a ramp up of the service prior to this time. The required operating

30 See submissions on the interim report from: ENA, p. 3; Delta Electricity, p. 3; TasNetworks, pp. 1-2.

level of inertia can therefore be influenced by both the amount as well as the speed of the contingency FCAS response.

Most FCAS is currently provided by synchronous generators. As synchronous generators become more scarce, the required level of inertia will increase and new sources of FCAS will need to be found for AEMO to be able to manage excursions in system frequency when they occur.

Meeting the required operating level of inertia

The required operating level of inertia determined for each of the defined network areas by AEMO will be set out in the NTNDP. The relevant TNSP would be required to meet the required operating level of inertia within each of the defined network areas.

The TNSP's proposal to meet the required operating level of inertia would be developed and set out as part of its APR. The TNSP's response to the required operating level of inertia could take the form of physically building assets or contracting services from third parties. The TNSP would determine the most economically efficient option for meeting the required operating level of inertia by comparing expressions of interest from third party providers against the option of physically constructing the required assets.

The value of the proposed investment will determine which regulatory process is undertaken in order to make an investment decision. Currently, a Regulatory Investment Test for Transmission (RIT-T) is applied for all augmentation investments greater than six million dollars. For investments under the six million dollar threshold, the TNSP has discretion to determine the most appropriate assessment.

Under the RIT-T, a detailed cost-benefit analysis is undertaken to identify the investment option which has the highest net benefits. The net economic benefit of a credible option is the expected market benefit less the expected costs of the option.[31]

TNSPs are required to consider all feasible network and non-network options. TNSPs are required to seek submissions from registered participants, AEMO and interested parties on the credible options considered as part of their investment test.

Third party providers of inertia services would draw upon the information contained in the TNSP's APR to identify potential opportunities where they could have the provision of their services considered as an option under the RIT-T process.

Under the RIT-T process, the credible option with the highest expected net economic benefit would be the option pursued first. Other options would subsequently be pursued to meet the required operating level of inertia in descending order of expected economic benefit.

An investment undertaken to meet the required operating level of inertia may still go ahead even if a RIT-T assessment determines that there is an associated negative net

31 AER, RIT-T application guidelines, June 2010.

economic benefit. Investments with negative net economic benefits are permitted under the RIT-T framework if the investment is undertaken to meet a reliability, system security or technical standards requirement. However, it must still be demonstrated that the investment is the least cost approach.

The TNSP may also enter into network support agreements (NSA) with third party providers to meet the required operating level of inertia. A NSA is a contractual arrangement between the TNSP and a third party that requires the third party to undertake a particular activity at certain times in order to support the operation of the network. It is often a more cost-effective means of efficiently operating the network than the construction of new assets. A NSA entered into to provide inertia would likely involve the TNSP contracting with a synchronous generator to be able to request them to be online at certain times, or to run in synchronous condenser mode.

Engie suggests that there may be limitations relating to the effectiveness of entering into a contract with a single synchronous generator to provide inertia.[32] Engie notes that a contract with a synchronous generator to come online to provide inertia is likely to cause another synchronous generator, which is also providing inertia, to be pushed out of the dispatch merit order, potentially resulting in only a small, or no, overall increase in inertia. Contracts between the TNSP and synchronous generators to provide inertia are unlikely to be effective unless:

- a set of constraints are applied equally to non-synchronous generators to ‘make room’ for the contracted synchronous generator; or
- all synchronous generators are paid to provide inertia.

The Commission considers that, in order for the TNSP to meet the required operating level of inertia, it may need to contract with multiple potential third party providers to make sure that the required level can be met at any given time.

When entering into contracts with third party providers, or constructing new assets to provide inertia, the TNSP will also need to take into account the implications for system strength. Meeting a required operating level of inertia and minimum required levels of system strength in a coordinated manner should be an inherent part of the TNSP’s planning process. A further discussion of the TNSP’s role in providing minimum levels of system strength is set out in chapter 5.

Cost recovery arrangements

The provision of inertia by the TNSP to meet the required operating level would be a prescribed service. Forecast capital and operating expenditure associated with meeting the required level would be set out as part of the TNSP’s revenue proposal for the relevant regulatory control period.

The required operating levels of inertia are likely to be updated on a periodic basis, which means that TNSPs may be engaging in the procurement of additional inertia

32 Engie Submission on the interim report, pp. 2-3.

during the regulatory period. In these circumstances, it is expected that the TNSP would be able to apply to the AER to have the costs of these services recovered under the cost pass-through provisions in the NER.

Whether consumers should be required to meet the costs of inertia services needs to be explored further. Some proportion of the TNSP's costs for acquiring inertia services to meet the required level could also potentially be recovered from generators. These costs could be recovered based on different generator characteristics to shift behaviour or drive generation investments towards a more secure operating system.

There are a range of factors that could determine the manner in which the costs are divided amongst generators. Costs could simply be recovered from generators that do not provide any inertia. Costs could also be recovered from generators on the basis of the physical characteristics that cause the required level of inertia. As discussed above, the level of required inertia is influenced by the size of contingency events and the tolerance of the system to high RoCoF. As such, costs could potentially be recovered from generators on the basis of their generation output or RoCoF withstand capability.

The Australian Energy Council (AEC) suggests that contributions to cost recovery could be determined on the basis of causer pays principles, such as varying in proportion to generation capacity online and not applying to generators that are offline.[33]

4.2.2 TNSP procurement of FFR services

As noted in section 4.1.2, before the introduction of a market sourcing approach for FFR, the Commission proposes to allow TNSPs to contract with third party providers of FFR services as an interim measure.

The early stage of FFR technologies and the limited use of FFR services in power system operation, specifically as a contingency service, suggest that contracts are likely to be the most appropriate mechanism with which to procure FFR services in the short to medium term.

The funding and trialling of FFR services by TNSPs may have long term benefits in developing a wider and diverse set of technologies for use in managing power system frequency. Promoting the use of FFR services may lower long term costs to consumers by cultivating a more competitive market environment.

TNSP contracts for FFR services would provide a basis for AEMO to develop specifications in relation to the service. This should allow for a more efficient transition to a market sourcing approach for the provision of FFR services in the longer term.

Once markets for FFR are in place it will no longer be necessary for TNSPs, to fund, as part of a prescribed service, their provision for the purpose of meeting the minimum level of inertia.

33 AEC, Submission on the interim report, p. 2.

AEMO notes that a similar trialling approach was taken to the development of the existing markets for FCAS. These services were originally procured through contracts and transitioned to a market once the required services and provider capabilities were sufficiently well defined.[34]

The TNSP procurement framework

TNSPs will be allowed to identify and pursue opportunities to procure FFR services. Provision of FFR services by the TNSP would be permitted as a substitute for part of the obligation to provide the required operating level of inertia, if approved by AEMO. AEMO would assess whether, and to what extent, the FFR delivered by the project could substitute for the delivery of inertia. This would be undertaken on a case-by-case basis in order to account for the varying characteristics of FFR services provided by different technologies.

As part of the approval process, TNSPs would be required to work closely with AEMO and potential service providers to assess the implications for network and power system operations. As with the delivery of inertia, a range of factors would need to be assessed by the TNSP in coordination with AEMO, including potential impacts on system strength at different locations, risk of intra-regional separation and islanding, and consideration of FFR services provided by generators with low RoCoF withstand capability. The availability and provision of the FFR service would need to be factored into the formulation of constraints for power system operation.

The TNSP would also need to make its own assessment of the benefits of pursuing different potential projects that deliver FFR services against each other and against the alternative of pursuing projects for the provision of inertia.

The TNSP's assessment of potential technologies that could deliver FFR services would form part of the TNSP's assessment of the most economically efficient option for meeting the required operating level of inertia. This assessment would be undertaken through the RIT-T framework for the provision of the required operating level of inertia if the expected cost of the investment is above six million dollars.

The TNSP's assessment of potential FFR technologies may be a complex task, as it might have to compare offers of very different service characteristics. As discussed in chapter 2, there are various characteristics of FFR that would need to be taken into account in comparing projects, including the capability to provide both raise and lower services, the design of the control systems as either open-loop or closed-loop, allowance for energy recovery periods following the provision of FFR, and the ability to ride-through faults and maintain active power levels.

In making an assessment, the TNSP would also need to take into account the range of other network support services that could be provided by projects in addition to the delivery of FFR. This may include such services as voltage support and load shifting.

34 AEMO, Submission on the interim report, p. 4.

The window of time for TNSPs to enter into contracts for the provision of FFR services would be limited to three years. While the Commission does not propose to apply a limit on the duration of contracts, the intention of this part of the package is to provide a transition pathway to the market sourcing approach as part of the subsequent package. As such, the Commission is considering whether a limit should be applied to the duration of contracts to be entered into by the TNSP to allow for a more streamlined transition to a market framework.

Once the market sourcing approach has been implemented, the provision of FFR services already procured by the TNSP would remain under contract. Any new projects for the delivery of FFR services would participate in the market.

The form and characteristics of TNSP contracts would need careful consideration. The details of the provision of the inertia or FFR services would need to be outlined in the contract, including the availability obligations for the provider over the term, conditions under which the service will be dispatched, and other operational protocols that need to be considered.

Payments could be structured as a combination of fixed charges and usage payments. A fixed availability charge would create certainty for investors who are supporting the provision of FFR services. However, there is potential for inefficiencies if the service contracted for a fixed charge is regularly under-utilised. If the provider of FFR failed to deliver the service up to the minimum level stipulated in the contract, then either withdrawal of availability payments or penalty payments may be considered.

Payment schedules based on availability and usage, penalties for non-compliance, testing of services, and evidence of results would consequently be key considerations as part of the contract terms.

Funding the delivery of FFR

FFR technologies represent a potentially lower cost method for the provision of frequency control. However, many of these technologies are in an early stage of development. The purpose of TNSP contracting would be to provide a source of funding for the provision of FFR services to trial the use of these technologies in power system operations.

The NER currently allows TNSPs to procure network support services through contracting with third party providers or otherwise constructing assets themselves.

To the extent the services being acquired are FFR services for the purpose of meeting the required operating level of inertia, funding under contracts with the TNSP would be limited to the provision of that service. This reduces the potential for funding services in addition to FFR services that might be delivered by the same technologies.

Ring Fencing

FFR services control frequency by rapidly injecting or withdrawing power in response to system disturbances. The injection of active power is measurable, which means that ring-fencing requirements may need to be applied to FFR services that are provided from assets owned by TNSPs. Ring fencing issues do not arise in relation to the provision of inertia services (it not being the provision of energy).

The possibility of contracting with third party providers of FFR services means that TNSPs may avoid the ring fencing requirements associated with asset ownership. However, the extent and nature of separation required will depend on the requirements set out in the ring-fencing guidelines applicable to the network business.[35]

In order to prevent TNSPs from gaining any undue advantage in other areas of the electricity supply chain by virtue of its position as a monopoly supplier of transmission network services, the nature of ring fencing that may be necessary when providing FFR (both on an interim and ongoing basis) will need to be considered further.

4.2.3 Generator obligations

The Commission considers that there may also be benefit in requiring generators to have certain capabilities as a condition of connecting to the network and participating in the market. Long term improvement to the management of system security may be derived from an obligation on new generators to have FFR capability or to be able to withstand high RoCoF.

FFR capability

The Commission considers there may be benefit in requiring new non-synchronous generators to have the capability to provide FFR services. AEMO, Hydro Tasmania and EnergyAustralia support the implementation of obligations for FFR capability as a partial component of managing overall system frequency and note that many non-synchronous forms of generation already have the ability to provide a fast response to frequency deviations.[36]

An obligation on generators to provide FFR capability would only apply to new entrants. The Commission understands that retrofitting FFR capabilities for existing generators is likely to be much more expensive than including the capability during the initial installation stage. Applying the obligation to existing generators has the potential to impose substantial costs. Reach Solar also notes that applying the obligation to existing generators could also be considered by investors as increasing sovereign risk and could potentially dissuade new investment.[37]

35 AER ring-fencing guidelines apply to all TNSPs in the NEM. These separate the accounting and functional aspects of prescribed transmission services from other services provided by a TNSP. Of particular relevance to issues around the provision of FFR, a TNSP is not allowed to carry on a related business which is defined as generation, distribution, and electricity retail supply that generates revenues of more than five per cent of the TNSP’s total annual revenue.

36 See submissions on the interim report from: Hydro Tasmania, p. 3; AEMO, p. 3. EnergyAustralia, Submission on the consultation paper, p. 3.

37 Reach Solar, Submission on the interim report, p. 4.

An obligation on new non-synchronous generators to have some form of FFR capability would mean that all new generators would be capable of providing some form of service to support system frequency. In the case of synchronous generators, this would be provided in the form of inertia.

The obligation on non-synchronous generators is not expected to be an onerous requirement[38] and is likely to result in a number of long term benefits. An obligation of this nature would increase the level of FFR available in the system and would provide a foundation to establish a competitive market for FFR services at some point in the future.

It is likely there would be lead times in determining and setting obligations on generators, and to allow generators to prepare systems and/or build infrastructure to meet the obligation.

An obligation for generators to provide FFR would need to consider the range of possible services. There are various forms of FFR, and some of the considerations that would need to be accounted for in designing a FFR obligation include:

- the design of control systems as open-loop or closed-loop;
- the interaction of the FFR service with other types of FCAS;
- whether the FFR should be capable of providing both raise and lower services; and
- the ability of the FFR to maintain active power input without going into a fault ride-through sequence.

An obligation on non-synchronous generators to have FFR capability would be most appropriately contained in generator performance standards, similar to existing related provisions. This would establish consistency in the application of the obligation across different jurisdictions.

RoCoF withstand capability

There may also be benefits in imposing other obligations on generators beyond the provision of FFR capability. Improving the capability of generators to withstand high RoCoF could also result in economic benefits by reducing the level of inertia and FFR required to manage system frequency.

The performance standards relating to the ability of generators to withstand rates of change of system frequency are set out in the NER . The current standards are automatically met if a generating unit can withstand a RoCoF of ±4 Hz/s for quarter of a second. Generators may negotiate a lower standard, but the minimum standard is ±1

38 GE Energy Consulting suggests that the capital costs for inclusion of FFR capability in new plant is expected to be on the order of less than one per cent of the capital cost of the overall project. GE Energy Consulting, *Technology Capabilities for Fast Frequency Response – Final Report*, 9 March 2017, p. 56.

Hz/s for one second. There is no obligation on generators to remain connected to the system through an event where RoCoF exceeds those levels, even if the frequency remains within the bounds of the FOS.

Increasing the level of the RoCoF performance standards may over time increase the tolerance of the system to sudden deviations in frequency as new connecting generators meet the higher standard while older generators with lower withstand capability retire. A further change that would likely improve the tolerance of the system would be to require generators to meet the minimum standard as a condition of meeting the automatic standard. This proposal was discussed in a report to AEMO prepared by DGA Consulting where it was suggested that it might be prudent to change the NEM automatic access standard so that it specifies a need to also withstand 1 Hz/s for one second.[39]

Box 4.2 EirGrid (Ireland)

Applying a RoCoF withstand capability as an obligation has been explored by Ireland's transmission system operator, EirGrid. EirGrid has proposed that, in order for Ireland's grid to meet higher levels of non-synchronous generation, a modification to the RoCoF withstand capability of generators would be necessary to maintain system security.

Prior to recent changes, the RoCoF withstand capability of all generators connected in Ireland was 0.5Hz/s. EirGrid indicated that an increased RoCoF standard will reduce the amount of wind generation curtailment and result in reduced wholesale energy prices. EirGrid initially proposed to increase the RoCoF standard to 4Hz/s but this was met by significant opposition from generators. EirGrid subsequently proposed to change the RoCoF withstand capability to 1Hz/s over 500ms.

A number of issues were raised in the process including the ability for generators to robustly confirm that their units would be compliant with the new standard as well as circumstances in which a generator may legitimately be incapable of complying.

The RoCoF withstand capability that EirGrid elected to implement is below both the minimum and the automatic access standards in the NEM. However, EirGrid still experienced a number of challenges around attempting to alter generator obligations. For EirGrid, it is not clear that the benefits of changing the RoCoF withstand capability outweigh the costs. The compliance tests were expensive and generally took between 12 and 18 months to complete. It is likely that similar challenges would arise if obligations were to be placed on existing generators in the NEM.

39 DGA Consulting, International Review of Frequency Control Adaptation – Report prepared for AEMO, 14 October 2016, p. 55.

4.3 Subsequent package

This section sets out, at a high level, the Commission's proposed second package of measures. This package would be subsequently implemented to enhance elements of the immediate package and affects the transition to a more market based solution.

The obligation on TNSPs to meet the required operating level of inertia and the obligations on new non-synchronous generators to have FFR capability would remain.

A TNSP incentive framework to guide efficient investments in the provision of inertia would be introduced. Under the incentive framework, TNSPs would be rewarded for the delivery of market benefits from a project to provide additional inertia that allowed for greater power transfer capability in the network.

The interim framework for TNSPs to contract with third party providers of FFR services would be replaced by a market for the provision of FFR services to optimise the FFR quantity consistent with system security requirements and levels of system inertia and other FCAS.

4.3.1 A TNSP incentive framework

An incentive framework would be introduced to allow TNSPs to identify and pursue opportunities to procure additional inertia beyond the required operating level of inertia where it results in net economic benefits through the alleviation of network constraints and improvements in the power transfer capability of the network. Such opportunities would be able to be identified by the TNSP during the regulatory period.

The identification of opportunities to provide inertia beyond the required operating level would be at the discretion of the TNSP. However, under the existing regulatory framework, the TNSP's decision to pursue the opportunities may be negatively influenced by a range of factors, including whether:

- the TNSP sees its planning role as inclusive of system security issues, as opposed to network reliability, replacement of ageing equipment, and forecast changes to supply/demand;
- the TNSP sees value in, and is willing to bear the risk of, incurring additional capital or operating expenditure which ultimately may not be deemed efficient and for which it cannot recover costs or receives little return, if it exceeds its revenue allowance.

It is possible that the TNSP may see little value in pursuing opportunities to provide inertia for market benefit purposes under the existing regulatory framework. The TNSP may be reluctant to enter into contractual arrangements with third party providers if it is required to demonstrate that the operational expenditure associated with the contract is efficient. Equally, the TNSP may build the physical assets and incorporate them as part of its Regulated Asset Base (RAB) but may be reluctant to do so if it perceives the capital costs to be too small, or that there is a risk that the AER may not deem the capital expenditure to be efficient, in the case that it exceeds its revenue allowance.

The objective of the development of TNSP incentive framework will be to mitigate these concerns.

Development of an incentive framework

Modifications to the arrangements may be required to provide a framework for the TNSP to invest in the provision of services that would provide market benefits and which are in addition to the required operating level of inertia. This may take the form of an incentive framework which would place a portion of the TNSP's revenue 'at risk', depending on their performance against a defined set of measures. This could be similar to the System Target Performance Incentive Scheme (STPIS) but with a system security focus.

The STPIS was established as an incentive framework for TNSPs to make efficient use of operational expenditure to improve levels of service to customers. While the scheme does not cover system security issues, it does provide an incentive for market benefits under the network capability component.

An incentive scheme for sourcing inertia for market benefits would need to assess the performance based on a counterfactual of the costs that would have been incurred if the additional inertia had not been sourced.

Box 4.3 The Service Target Performance Incentive Scheme

The STPIS is designed to provide TNSPs with an incentive to maintain and improve their service levels. Under the scheme, a portion of the TNSP's revenue is placed 'at risk', depending on their performance against a range of measures. These measures fall into three broad categories:

- Service – based on achieving a reduction in network failures and an improved level of service to customers;
- Market impact – based on the alleviation of network constraint impacts associated with outages; and
- Network capability – based on incremental investments to enhance the performance of the existing network.

The market component aims to improve network availability and reduce network congestion at times most important to the market. It operates by measuring the number of dispatch intervals when an outage of a network results in a constraint binding with a marginal value greater than $10/MWh (MIC count). This is then compared against the AER target which is an average of the median five of the last seven years performance. The dollars per dispatch interval ($/DI) associated with the reward/penalty for each count can be directly calculated for the regulatory control period from the MIC target, and the MAR.

Both the target and the $/DI are fixed for the regulatory control period.

The network capability component encourages TNSPs to examine their networks to identify suitable low cost one-off operational and capital expenditure projects that improve the capability of the transmission network at times when it is most needed.

This requires TNSPs to submit a Network Capability Incentive Parameter Action Plan (NCIPAP) as part of their revenue proposal which consists of a set of projects designed to improve network limitations and are ranked in priority based on the likely benefits to customers and the market. TNSPs must consult with AEMO when developing their NCIPAPs. AEMO's role includes prioritising and ranking the projects in order of best value for money for consumers.

The AER assesses each project against its improvement target. When determining whether a priority project improvement target would result in a material benefit, the AER takes into account the likely benefits to the wholesale market or to customers. A material benefit of the achievement of the target would be the effect it would have on spot price outcomes or improved capability of the transmission system.

Total annual average expenditure on these priority projects cannot exceed one per cent of the TNSP's proposed maximum allowable revenue (MAR) and cannot be funded elsewhere through operating or capital expenditure from their revenue proposal.

TNSP provision of physical assets for market benefit

TNSPs recover the cost of capital expenditure through a regulated rate of return on their investments over the life of the assets. This is in contrast to third party contracting where operational expenditure is recovered from consumers at the time of the expenditure without a return. As such, if TNSPs expect to be able to source funds at a lower cost than the regulated rate of return, the existing regulatory framework may provide an incentive for TNSPs to directly invest in the construction of physical assets rather than enter into contract arrangements with third party providers.[40]

The potential bias towards constructing new assets could lead to a less efficient overall outcome if the same services can be provided by existing synchronous generators at a lower cost. It is possible that contracting with existing synchronous generators for the provision of inertia services may be a lower cost option than constructing new assets and should be considered as part of any assessment to procure additional services for market benefit.

40 The extent to which this incentive exists and is actually driving a bias towards the construction of physical assets by TNSPs is currently being explored as part of the Commission's assessment of the rule change request relating to the contestability of energy services.

However, a properly designed incentive framework may limit this imbalance by allowing the TNSP to share in the economic benefits that are accrued through contracts with third parties providers.[41]

4.3.2 Market sourcing of FFR services

FFR services are likely to be able to be co-optimised with the provision of energy through the existing energy market dispatch process, similar to the existing markets for FCAS.

There are a range of different potential designs for a market sourcing approach to FFR. A number of service providers that currently participate as part of the existing six-second FCAS, initiate their response much earlier than six seconds. As such, it may be possible for some forms of FFR to also participate in the current six-second service. However, there may be a number of drawbacks to relying on the existing arrangements, including that:

- payments to service providers under the existing six-second FCAS are based on an average response over the six-second period and as such do not place greater value on the much faster response capable of being provided by FFR technologies; and
- there may be some issues associated with trialling FFR technologies while at the same time procuring them as part of the six-second FCAS to respond to contingencies.

It is likely that a separate market for FFR will be required to account for the faster response of the service. It is conceivable that a separate market for FFR would be an additional form of FCAS, including separate raise and lower services that are dispatched and settled on a five-minute basis.

The exact definition of the service would need careful consideration but would likely be defined in terms of the minimum response time and associated ramp and taper assumptions. For example, an FFR service may be specified as a one second response time. This service would be provided in conjunction with the existing six-second, 60-second and five-minute response services.

There is likely to be significant interaction between these different services. For example, some existing six-second contingency services may actually be capable of providing a faster service but this will be dependent on the exact definition of the FFR service. Equally, some FFR technologies may not only be able to initiate an active power response very quickly but also be able to sustain that response for an extended

41 The most recent review of the RIT-T framework by the COAG Energy Council explored the potential benefits of a greater degree of oversight of the RIT-T process by the AER. The review suggests that increased oversight could address concerns that TNSPs have a strong existing incentive to pursue network solutions over non-network solutions when undertaking projects to improve the capability of the network. COAG Energy Council, *Review of the Regulatory Investment Test for Transmission*, 6 February 2017, pp. 24-25.

period of time. EnergyAustralia considers that significant understanding will be needed of the interaction of FFR with the existing six-second service, in order to avoid degrading the value of the service and avoiding possible coordination issues.[42]

As such, a broader consideration of FFR services in the context of existing FCAS may be necessary. Pacific Hydro suggests that frequency control services should be continuous rather than being switched between services, as this would provide for a more dynamic management of system frequency.[43]

A possible approach could be to alter the way the current six-second service is defined so as to better reward faster response. For example, instead of defining the bid energy as the average MWs delivered over the six seconds following the contingency, it may be more appropriate to calculate the actual energy delivered over those six seconds and then price the response provided according to the speed of the response.

There is also likely to be significant interaction with the level of inertia sourced by the TNSP. There are likely to be challenges in co-optimising the blend of inertia and FFR where inertia is sourced by the TNSP through separate arrangements. Substantial integrated planning is likely to be required to co-optimise the provision of the services over time.

A FFR service is likely to substitute for inertia to some extent. The target FFR quantity will be related to the level of inertia available at any point in time and the contingency size that is sought to be protected against. Real time optimisation of FFR quantity consistent with system security requirements and interaction with inertia (and ideally system strength) will require development of suitable models and clear definition of the nature of the FFR service.

Prices could either be set based on price offers by potential providers of FFR or by the market operator nominating a price that will be paid for any (and all) FFR dispatched. That is, price could either be set:

- in a manner consistent with the current contingency FCAS markets. This implies five minute dispatch intervals and five minute settlement where price equals the marginal supply offer. This option should be just as effective for an FFR service as for other contingency FCAS services and has the benefit of eliciting competitive bids which can enhance price discovery.

- by the market operator prior to participants bidding FFR volumes based on some shadow price calculation such as estimated (or actual) inter-regional price differences. This option has the benefit of potentially minimising the opportunity for FFR market participants to utilise any pricing power they may have and also to tie the price back to the energy market. However, in doing so it may not signal the value of FFR to system security and therefore not encourage sufficient (efficient) investment going forward.

42 EnergyAustralia, Submission on the interim report, p. 3.

43 Pacific Hydro, Submission on the interim report, p. 10.

Given that existing contingency FCAS markets use a marginal offer price solution, a similar solution for FFR services would ensure consistency and transparency for market participants.

The principal issue with implementing new markets for the provision of FFR services at this time is the lack of existing providers of FFR services, the fledgling state of the technologies that provide such services, and the lack of experience and understanding as to how the operation of the power system might be impacted. Many FFR technologies are in the early stages of development with limited examples of FFR currently being actively used to manage power system operations in overseas jurisdictions, particularly with respect to responding to contingency events.

A greater level of experience with using FFR services to control system frequency is required before a service could be properly specified and a five-minute market developed that would be able to be co-optimised efficiently with the existing energy and FCAS markets. Delta Electricity suggests that this transition should be contingent on a thorough assessment of the performance of each type of FFR technology in supporting system security.[44]

A market sourcing approach to FFR offers a less certain revenue stream to prospective investors than would be offered under a contract approach. Care will need to be taken when transitioning to a market sourcing approach that sufficient FFR services are available to provide for a competitive market environment and the creation of efficient price signals for investment. This issue may be less significant if the revenue from an FFR market is one of a number of sources of revenue obtained by the technology providing the service, such as participation in the energy market or provision of hedging services.

44 Delta Electricity, Submission on the interim report, p. 3.

5 Proposed approach to system strength

Box 5.1 Summary

Recently, system strength in some parts of the power system has been decreasing as a number of traditional synchronous generators are operating less or are being decommissioned. Low levels of system strength can cause a number of issues, including a reduction in:

- the capability of some transmission and distribution network protection systems, which rely on a high fault current to operate effectively;
- the ability of network operators to manage voltages within their networks; and
- the ability of generators to operate correctly such that they can meet their technical performance standards.

There are a range of technical solutions that can be used to address these issues, including upgrading protection systems and installing voltage control devices, reinforcing the network or, ultimately, restoring system strength with additional synchronous machines.

The existing rules place the obligation for maintaining the operation of network protection systems and the control of network voltage on the relevant NSPs. However, responsibility for ensuring that system strength is maintained such that generators can meet their technical performance standards appears less clearly defined.

The Commission's proposed approach is to amend the rules to clarify that NSPs should be responsible for maintaining an agreed minimum short circuit ratio to connected generators. Where the entry of a new generator would cause minimum short circuit ratios to be breached for one or more existing generators, the NSP would be entitled to recover the costs of the remedial actions from the connecting generator on a "causer-pays" basis.

These amendments would be implemented concurrently with the immediate package described in Chapter 4.

5.1 Background

5.1.1 What is system strength?

System strength is an inherent characteristic of a power system and it relates to the size of the change in voltage for a change to the load (or generation) at a connection point. When the system strength is high at a connection point the voltage changes very little for a change in the loading, however, when the system strength is lower the voltage would vary more with the same change in load.[45]

In addition, when a fault occurs at a connection point the current that flows into the fault is higher when the system strength is higher. This is why the system strength at a point in the power system is often referred to as the fault level.

5.1.2 What affects system strength?

The system strength at a point in the power system depends on how well it is connected to the synchronous generating units in that part of the power system. The system strength will be higher when:

- there are a number of large generating units nearby
- the point is connected to these generating units with more transmission (or distribution) lines and transformers.

Non-synchronous generators do not contribute to system strength as much as synchronous generating units, if at all. However, some modern inverter based generation can provide a limited contribution to system strength. It is possible that future inverter based generation will be able to make a greater contribution to the system strength.

5.1.3 How is system strength expressed?

The system strength can be expressed as the magnitude of the current that would flow into a fault at a given point in the system and thus measured in Amperes (A). However, it is more common to express the fault level as the product of the fault current and the nominal voltage, and thus measured in MVA.[46]

Also, the system strength for a generating unit or inverter system etc can be normalised by dividing the MVA by the size of the generating unit or inverter. This is referred to as the short circuit ratio (SCR).[47]

5.1.4 Faults in power systems and their management

Faults in a power system are a short circuit between the conductors in the power system. This can occur between the conductors on a transmission or distribution line when it is struck by lightning, the conductors are exposed to bush fires or when an

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45 AEMO published a "Fact Sheet: System Strength" in August 2016 that provides further description of system strength and the impacts on power system security.

46 A system strength of 1000 MVA at a location in the power system with a nominal voltage of 330 kV would have a fault current of 1.75 kA, that is $1000 \div (\sqrt{3} \times 330)$. The $\sqrt{3}$ is required for three phase systems.

47 A 200 MW generating unit at a connection point with a system strength of 1000 MVA would have a SCR of 5, that is $1000 \div 200$.

insulator is damaged. Faults can also occur within items of electrical plant such as transformers or reactive banks when the plant is damaged.

It is important that the item of plant where the fault is located is isolated from the remainder of the power system. This is often referred to as clearing the fault and is essential so that:

- damaged to equipment is limited
- safety is maintained
- the remainder of the power system can continue to operate.

When faults occur in the power system they are cleared using circuit breakers. Each component of the power system is connected to the surrounding network through circuit breakers. When the protection systems detect the presence of a fault within an element, such as a transformer or transmission line, they automatically operate the associated circuit breakers to isolate the faulted component, thus clearing the fault. The protection systems need to be sufficiently sophisticated to not only detect the presence of the fault but also determine which items of equipment are affected. If the protection system is unable to correctly discriminate where the fault is then the fault may not be cleared within an appropriate time, if at all, or the wrong circuit breakers may be operated which could disconnect healthy equipment or transmission lines.

The speed at which the faults are cleared is critical to both limit the risks of damage and to safety, as well as the ongoing operation of the power system. The maximum allowable fault clearance times for different voltage levels are in Table S5.1a.2 of the NER. The table specifies faster clearance times for high voltages as the consequences of prolonged faults are greater.

5.1.5 Maximum allowable system strength

Historically, the primary concern of power system engineers has been that system strength may be too high and fault currents may damage equipment. This is because networks have been reinforced and additional generation has been installed over time as the demand for electricity has increased.

High faults levels become an issue if the fault level at a location exceeds the rating of the affected electrical equipment. Of particular concerns are the circuit breakers required to interrupt fault currents and the mechanical structures such as buses, transformers etc that may be required to carry the fault current until that is interrupted by the relevant circuit breaker.

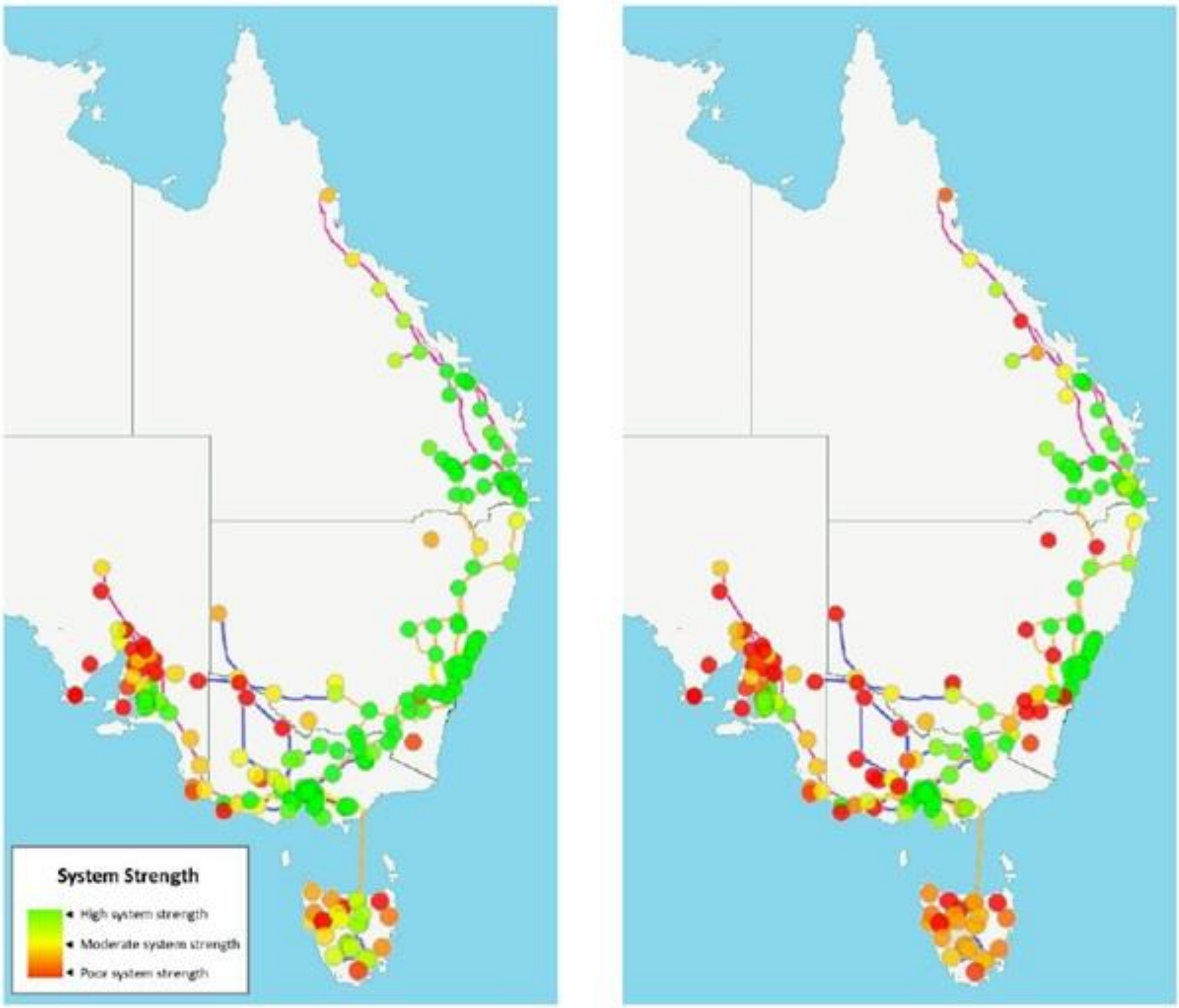
Clause 4.6.1 requires AEMO to have processes in place to determine the fault levels for normal operation and anticipation of credible contingencies. In addition, the relevant NSPs will need to consider the system strength when operating their networks, considering augmentations to their networks and when assessing applications to connect new generation.

5.1.6 Low system strength is an emerging issue

While historically high fault levels have been the main concern, more recently system strength in some parts of the power system has been decreasing as traditional synchronous generators are operating less or being decommissioned.

In the 2016 National Transmission Network Development Plan, AEMO projected that over the next 20 years there will be a reduction of around 15 GW of synchronous plant in the NEM, while there will be over 22 GW of large-scale inverter-connected generation connected (not including rooftop PV).[48] This displacement of synchronous generation is projected to greatly reduce system strength across the NEM, as shown in Figure 5.1 below.

Figure 5.1 System strength assessment in 2016–17 (left) and 2035–36 (right)



Source: AEMO, *National Transmission Network Development Plan*, December 2016, Figure 27.

In the 2016 NTNDP, AEMO performed a high-level assessment of where system strength is an existing or emerging challenge. An area of the grid is generally

48 AEMO, *National Transmission Network Development Plan*, December 2016, p. 66.

considered weak if the SCR drops below three.[49] For this assessment, AEMO weighted the SCR[50] to determine network strength.

Box 5.2 Low system strength in South Australia

On 13 November 2016, the South Australian power system was operating with one synchronous generating unit in service for several hours.[51] Following a preliminary analysis of the period, AEMO concluded that two large synchronous generating units are required to be online in South Australia to ensure a secure operating state.

While system strength is essentially a localised effect, the only sources of system strength in South Australia are from the synchronous generation operating in South Australia plus a limited contribution from the Heywood interconnector. Thus when only a small number of synchronous generating units are operating in South Australia, the system strength for the whole region mainly depends on these units.

AEMO considers that operating the South Australian power system with less than the equivalent of one Torrens Island B unit would result in the system strength being reduced across all of the South Australian network to the extent that voltage variations could be beyond the levels that are acceptable under Schedule 5.1.4 of the Rules, with or without a contingency event. In addition, AEMO considers the low system strength could also violate the stability criteria defined in Schedule 5.1.8 of the Rules. In both cases this is due to increased voltage sensitivity to small changes in reactive power flows in the network making the voltage volatile and difficult to control.

Therefore, as AEMO considers that at least the equivalent of one Torrens Island B unit is required for the system to be stable, it is necessary for the equivalent of two such units to be operating for the system to be secure. AEMO formed this view because clause 4.2.4 of the NER requires that the system must be expected to operate satisfactorily following a credible contingency, such as the tripping of the largest generating unit in South Australia.

AEMO has indicated that it will, in collaboration with ElectraNet, publish a report in early 2017 to explore the requirement further. In particular, AEMO and ElectraNet will consider whether this requirement constitutes a new NSCAS gap.[52]

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49 Y Zhang, S Huang, J Schmall, J Conto, J Billo, E Rehman, "Evaluating System Strength for Large-Scale Wind Plant Integration", PES General Meeting Conference & Exposition, 2014 IEEE.

50 Weighted short circuit ratio takes into account the interaction between inverter-connected generation on the short circuit ratio.

51 See: http://www.aemo.com.au/-/media/Files/Media_Centre/2016/SA-System-Strength.pdf.

52 AEMO, *National Transmission Network Development Plan*, December 2016, p. 98.

The specific issues arising from low levels of system strength, such as those now being experienced in some parts of the NEM, include:

- the capability of some transmission and distribution network protection systems, which rely on a high fault current, to operate effectively;
- the ability of NSPs to manage network voltages within their networks to the required standards;[53] and
- the ability of generators to operate correctly such that they can meet their technical performance standards, as failure to do so can increase the risk of cascading outages leading to major supply disruptions.

The remaining sections of this chapter discuss each of these issues, and the Commission's proposed approach to them, in turn.

5.2 Ability of protection systems to operate correctly with reduced system strength

5.2.1 Nature of the issue

The performance of transmission and distribution protection systems may deteriorate if the system strength reduces over time. This is because many of the algorithms used in the protection relays rely on the presence of large currents flowing into a fault to determine its location.

If one or more of the protection systems in the network are no longer fit for purpose, it may mean that the protection system may:

- not always detect the presence of a fault on the component of the power system that it is required to protect, resulting in an extended duration of the fault
- falsely detect the presence of a fault on another component of the power system, resulting in a larger part of the power system being isolated which is likely to affect more generators and customers.

5.2.2 Technical solutions

When a protection system can no longer be expected to operate correctly then it would be necessary to either upgrade the protection system or restore the system strength.

Isolated protection issues

In the absence of another low system strength issue such as a voltage control or generator performance issue, the cheapest way to rectify a protection issue that is localised to an isolated part of the power system is likely to be upgrading the

53 Australian Standards AS/NZS 61000.3.7:2012.

protection system. This may simply consist of adjusting the settings on existing protection relays to be able to operate over a large range of system strengths, but could require new relays (with more sophisticated algorithms) to ensure that the protection system continues to be fit for purpose when the system strength is low.

In some cases it may also be necessary to install new current and voltage transformers to provide additional information to the relay. In addition, some more sophisticated transmission line protection systems require a high speed communication link between the substations at each of the lines.

Widespread protection issues

While individual localised protection issues may be corrected at a reasonable cost, this approach may not be cost-effective where the system strength is reduced across a large portion of the power system, such as the majority of a region. To address such systemic protection issues would require extensive studies, and it would potentially be very expensive to replace and test the protection systems. In some cases it may not be possible to provide adequate protection, even with upgraded systems.

Therefore, it may be necessary to restore the system strength within the affected portion of the power system using synchronous condensers or contracting existing synchronous generators. Restoring the operation of the protection systems using synchronous condensers or synchronous generation would likely:

- be lower cost, especially if the synchronous machines were also required to rectify other system strength issues within the affected power system
- present a lower risk as the protection systems would continue to operate in the manner in which they were designed.

Distribution protection issues

The mal-operation of protection systems at low fault levels is not restricted to transmission networks. Distribution networks consist of many thousands of individual transformers, overhead lines and cables, and each of these requires some form of protection system. In most cases, protection is provided by the use of fuses. These fuses are the simplest form of protection that operates when the current exceeds a threshold which is chosen such that:

- the normal currents that flow in the network to supply customers etc do not exceed the threshold
- the currents that flow during a fault exceed the threshold, which results in the fuse operating to isolate the item of faulted equipment.

However, when the system strength in the distribution network reduces, the fault currents reduce making it more difficult or impossible to distinguish between normal operate and fault conditions. A lower than anticipated fault current can mean that the fuses do operate but a lot slower than desired, resulting in unnecessary risk or damage to the affected network equipment. Therefore, the only practical way to ensure that the distribution system fuses operate correctly may be to maintain the system strength to a sufficiently high level.

The system strength could be maintained by either the distribution network service provider (DNSP) or the TNSP that supplies the network distribution network. Currently most of the system strength within the distribution networks comes from their connections to the transmission network and could therefore be maintained when the TNSP maintains the system strength of its network. Alternatively, the system strength of the distribution network could be maintained by the DNSP itself such as with synchronous condensers or contracting with synchronous generation. Therefore, it is important that the joint planning processes between the TNSPs and the DNSPs consider the most efficient options to address the system strength issues in both networks.

5.2.3 Allocation of roles and responsibilities

Currently, NSPs are responsible for the provision and operation of the protection systems for their networks.[54] There appears no reason to change this in the future for parts of the network where the system strength is reducing over time.

The Commission's proposed approach is therefore not to make changes to the Rules in relation to the management of network protection systems during periods of lower system strength. What will be important, however, is that both TNSPs and the DNSPs become aware that:

- they face risks with their protection systems not operating correctly and should be reviewing the need for mitigation measures, such as increasing system strength through synchronous machines
- the issues faced in the distribution networks may require actions within the transmission networks, which may be in addition to any measures that the TNSP needs to take to address the low fault level issues within its network.

5.3 Ability to manage network voltages with reduced system strength

5.3.1 Nature of the issue

NSPs are required to keep the voltage at network users' (including customers' and generators') connection points within technical limits, including:[55]

- the absolute level of voltage must be in a defined range

54 Schedule 5.1 of the Rules requires NSPs to maintain the performance of the protection systems within their networks.

55 These requirements are specified in Schedule 5.1 of the Rules, as well in Australian Standards and in jurisdictional licensing conditions.

- step changes in the level of the voltage must be smaller than the limits required by Australian Standards

- voltage unbalance must be smaller than the limits required by Australian Standards.

This becomes increasingly difficult as the system strength at the connection point decreases. This is because the voltage at the connection point changes more for a given change in the load or generation at the connection point, or the switching of a capacitor or reactive bank. Of particular concern is that automatic voltage control systems can become unstable at low fault levels.

5.3.2 Technical solutions

The potential technical solutions for voltage control problems depend on their severity and include:

- reinforcing the network with additional lines and/or transformers

- switchable capacitor and reactor banks

- dynamic voltage control devices such as static VAr compensators (SVCs) and static synchronous compensators (STATCOMs)

- synchronous condensers.

Reinforcing the network

Reinforcing the network that supplies the connection point can increase its system strength. This could consist of additional transmission lines or transformers supplying the connection point, or by connecting to the network at a high voltage. The other advantage of reinforcing the network supplying a connection point is that it increases the size of the load or generating unit that can be connected.

Switched capacitor and reactor banks

Less severe voltage control issues can be resolved by installing switchable capacitor or reactor banks. These banks are normally switched automatically in response to the voltage but can be switched manually. A typical voltage control scheme using switched capacitor and/or reactive banks would include multiple capacitor banks to inject reactive power and may include reactor banks to absorb reactive power.

When the voltage at the connection point is lower than a threshold, an additional capacitor bank would be switched on, injecting reactive power into the network causing a step increase to the voltage at the connection point. Similarly, when the voltage is higher than a threshold, one of the capacitor banks can be switched off, reducing the injection of reactive power causing a step decrease to the voltage. The effect of switching reactive banks is the opposite.

The size of the voltage step is proportional to the size of the capacitor or reactor bank (in Mvar) being switched and inversely proportional to the system strength (in MVA). Therefore, the size of the switched capacitor or reactor banks needs to be sufficiently small so that the voltage step does not exceed the relevant standards for the minimum foreseeable system strength. If the system strength falls below this minimum level then, as well as the voltage steps exceeding the allowable standard, the associated voltage control scheme could be unstable.[56]

Static VAr compensators (SVCs) and static synchronous compensators (STATCOMs)

SVCs and STATCOMs are power electronic devices that provide dynamic reactive support at a connection point by automatically adjusting the reactive power injected or absorbed at the connection point as the system conditions change, such as the voltage at the connection point.

The advantage of SVCs and STATCOMs over switched capacitor and reactor banks is that the level of reactive power is infinitely variable between the maximum levels of absorption and injection. This means that they are inherently more stable and can be used to improve the stability of the power system. Also, the operation of SVCs and STATCOMs is much less affected by the system strength, compared to switched banks, but such devices still require a minimum system strength to operate. An SVC or STATCOM could be used to stabilise the operation of a switched capacitor and reactor bank scheme.

The disadvantage of SVCs and STATCOMs is that they cost significantly more than a similarly sized switched capacitor and reactor banks scheme. An SVC does not contribute to the system strength of the power system where it is connected, while a STATCOM may provide a limited contribution to the system strength.

Synchronous condensers

As referred to elsewhere in this paper, a synchronous condenser (sometimes called a synchronous capacitor or synchronous compensator) is a spinning device, similar to a synchronous generator or motor, but whose shaft is not connected to a generating unit or motor load, instead spinning freely. Synchronous condensers can both inject and absorb reactive power at their connection point and their output is infinitely variable within their capability.

While the cost of synchronous condensers is approximately twice that of SVCs and STATCOMs,[57] they also contribute directly to the system strength at their connection points. That is, as well as providing an ability to control the voltage at its connection

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56 A voltage control scheme that is based on switched capacitors and/or reactors would go unstable if the voltage step when a capacitor or reactor bank switches exceeds the difference between the thresholds to switch banks in and out. For example, if switching in a capacitor caused the voltage to increase from below the lower voltage control threshold to above the higher voltage control threshold then the control scheme would respond by switching the capacitor back out, thus becoming unstable.

57 Electranet, *Northern South Australia Region Voltage Control*, RIT-T: Project Control Specification Consultation Report, August 2016, p. 4.

point, a synchronous condenser also increases the system strength in that part of the power system.

In addition, synchronous condensers also provide inertia when they are operating, and thus contribute to the ability to manage the system frequency.

An alternative to installing additional synchronous condensers would be to contract with synchronous generators to operate their units at times when the voltage is difficult to control.

5.3.3 Allocation of roles and responsibilities

Currently, NSPs are responsible for the management of the voltage within their network.[58] As with issues associated with protection systems, it is not clear that there is any reason to change this allocation of responsibility in the future for parts of the network where the system strength is reducing over time.

Box 5.3 AEMO's role in the dispatch of reactive power

While NSPs have clear responsibility for planning their networks to allow for the management of voltage, AEMO has an operational role at a transmission level, being responsible for the dispatch of reactive power from scheduled generating units with the objective of setting the profile of the voltage throughout the high voltage network (needed to maximize the transfer capability of the network while maintaining the power system in a secure operating state). AEMO dispatch instructions to scheduled generating units, semi-scheduled generating units, scheduled network services and scheduled loads can include reactive power outcomes (clause 4.9.5(a)(2)).

AEMO is required to determine the levels of reactive power reserve that are required to operate the power system (clause 4.5.2(a)). AEMO is also required to ensure that appropriate levels of reactive power reserves are available (clause 4.3.1(k)). AEMO further determines NSCAS needs that include the provision of reactive power reserves, including arranging the provision of reactive power facilities through ancillary services contracts (clause 4.5.1(f)). This can includes reactive power from synchronous generating units and synchronous condensers (clause 4.5.1(g)).

If the available reactive power reserves prove to be insufficient to keep voltages within acceptable limits, AEMO is required to take all reasonable actions to the extent necessary to return the voltages to acceptable limits (clause 4.5.2(b)). Such actions could include directing participants such as generators to reduce their output or limiting flows within the transmission network.

58 Schedule 5.1 of the Rules, Australian Standards and jurisdictional licensing conditions place obligations on NSPs to control the voltages within their networks to maintain the quality of supply to the users of their networks, in accordance with the relevant standards.

The Commission is therefore not proposing to amend the rules to alter the current allocation of roles and responsibilities in relation to voltage management during periods of lower system strength.

It will, however, be important that NSPs work together to coordinate the planning of their networks and consider the need to increase system strength in their networks. In particular, voltage control issues within transmission and distribution networks are often not anticipated in planning studies but occur in the real power system. This is because:

- voltage control issues are more likely to occur under unusual outage conditions that are generally not considered in planning studies
- there may be a lack of awareness by some network service providers as low system strength voltage control issues are not common yet in most networks.

A further issue for attention is the fact that the traditional models used to assess the behaviour of the power system are becoming less accurate at low system strengths and low inertia, and are generally optimistic about the security of the power system. Therefore, to accurately model the security of the power system, data for more detailed models is likely to be required. This is the subject of a Rule change proposal recently received from AEMO.[59]

5.4 Ability of generators to meet their performance standards with reduced system strength

5.4.1 Nature of the issue

The security of the power system relies on AEMO knowing the technical performance of the generating units in the NEM, or at least their minimum performance, and the generating units meeting these performance standards.

The generator performance standards are based on schedule 5.2.5 of the NER, which contains 14 specific technical performance requirements. Each of these technical requirements includes an automatic level and a minimum level.[60] A performance standard for a connecting generating unit for a specific technical performance requirement must be accepted if it equals or exceeds the automatic standard. Alternatively, the generator can negotiate with the NSP to a lower technical performance requirement, provided the performance exceeds the minimum level.

When a generator is the proponent of a generating system it must provide the NSP and AEMO with sufficient information to assess its expected impact on the operation of the

59 AEMO, *Rule change submission for revision of AEMO's generating system model guidelines*, Electricity rule change proposal, 28 October 2016.

60 Schedules 5.2.5.6 and 5.2.5.8 for "quality of electricity generated and continuous uninterrupted operation" and "protection of generating systems from power system disturbances" only contain a minimum performance level that must be met.

power system. This will include the type of generating system being considered, detailed models and the associated control and protection systems.

AEMO provides the generator and NSP with advice when the technical performance requirement relates to its functions, including power system security. Once the connection negotiations are finished, the agreed performance standards are included in the connection agreement and registered with AEMO.

Generators are required to have compliance programs to ensure their ongoing compliance with the agreed performance standards. The Commission understands that the negotiated performance standards include a reference to maximum and minimum system strength levels. That is, the generator must continue to meet its performance standards whenever the system strength is within this range.

System strength is reducing as synchronous generating units exit

Recently, the system strength has been reducing in some parts of the NEM power system as a number of synchronous generating units exit the market, or are operating less, and are replaced by new non-synchronous generation that does not contribute as much to system strength. There are concerns that the generating units in the NEM will no longer be capable of meeting their performance standards at periods of low system strength and that this could lead to a cascading outage or major supply disruption, or even potentially a black system condition.

Of particular concern is the operation of the inverters such as those for modern wind farms, HVDC interconnectors, solar PV and battery storage. This is because inverters require sufficient system strength to be able to meet their generator performance standards, such as being able to operate stably and to be able ride through a fault, ie continue operating after a fault in the nearby power system has been cleared.

The impact of low system strength also affects the operation of distributed energy resources such as distribution connected and residential solar PV and battery storage systems. These devices interface to the power system using inverters which require a minimum system strength to operate.

Connection of new non-synchronous generation

Another issue is the connection of new generating units near existing generating units in a weak part of the power system.

The behaviour of a combination of some existing and new generating units could be approximated by a single (large) equivalent non-synchronous unit. This means that the short circuit ratio at the connection point (ie the ratio of the system strength to the rating of the connected non-synchronous generation) would decrease as additional new units are connected, even if the system strength was not decreasing. The lower short circuit ratio could lead to the affected units being unable to operate stably and ride through faults.

5.4.2 Technical solutions

The potential technical solutions when a generator is unable to meet its technical performance depend on the nature of the non-conformance and the circumstances of the connection, but they include:

- operating the generating unit at a reduced level of output may be an immediate solution in some instances but may be unacceptable as a long term solution, both from the perspective of the generator and given the wider consequences (see Box 5.4)
- reinforcing the network with additional lines and/or transformers
- SVCs and STATCOMs can help in some instances
- installing synchronous condensers or contracting with other synchronous generation to increase the system strength at the connection point.

Box 5.4 Consequences of not maintaining the short circuit ratio for existing generating systems

If the short circuit ratio for existing generating systems is not maintained, there will be uncertainty as to whether the generators will be able to meet their performance standards. This is particularly true when there are multiple generating systems within a weak part of the network and complex interactions between the individual generating systems. A reduction in the output of any of the individual generating systems is likely to improve the performance of all the affected generating systems. However, each generator would rely on the other generators to reduce output to maintain system strength. There is no incentive for generators to collectively manage reductions in system strength.

Therefore, the operation of multiple generating systems would need to be centrally coordinated. Operationally this would mean the NSPs and AEMO would need to develop constraint equations to maintain system security by limiting the output of the affected generating systems so that they would be expected to meet their performance standards. However, as the system strength reduces, the interactions between the affected generating systems become more complex and the currently used power system models become less accurate. This means that unless the system strength is maintained there would be increasing uncertainty as to whether the system is in a secure operating state.

In addition, relying on constraint equations to maintain system security means that it could be difficult to enforce generator compliance. This is because when a generator does not meet its performance standards it could be due to the accuracy or implementation of the constraint equation rather than an actual failure of the generator to maintain its technical performance.

5.4.3 Allocation of roles and responsibilities

The Commission understands that some connection agreements[61] only require generators to comply with their performance standards when the system strength is above the minimum considered at the time the connection agreement was negotiated. However, the Rules appear not to place an obligation on any party to maintain the system strength, particularly when:

- a number of synchronous generating units exit the market, or are operating less
- a number of planned or unplanned network outages occur that reduce the system strength at a connection point.

Therefore, when the system strength drops below the minimum level considered during the connection process, it is possible that some generators would not meet their performance standards if a major contingency were to occur. Given the potentially severe consequences of this, there is a need to allocate responsibility to one or more parties to maintain the short circuit ratio for existing generating facilities.

Issues associated with requiring existing generators to manage their performance when system strength reduces

Existing generators affected by reducing system strength would have little capability to manage the issues associated with low system strength other than to install a dynamic reactive power controller (such as a SVC or STATCOM) or a synchronous condenser.

However, when there are multiple generating systems in an affected part of the network, this investment would also benefit the other generators, who could "free ride" when the system strength constraint is relaxed. That is, the generator that installs the new equipment may not be able to capture all its benefits. This is likely to lead to inefficient:

- investment in synchronous condensers, as each generator would be incentivised to free ride on others' investments
- operation of synchronous condensers, as the owner would be incentivised to turn off its synchronous condensers[62] when its generating system is not operating, thus reducing the capability of its competition.

In addition, relying on affected generators to install synchronous condensers could be problematic when the reducing system strength is also causing protection or voltage control issues for the NSP. In this situation, efficient investment in synchronous condensers is not likely to occur as the generators and NSPs may be incentivised to wait for the other to invest first.

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61 Connection agreements are commercial contracts between the NSP and the generator, and their contents are confidential.

62 Turning off the synchronous condenser would reduce the cost of losses and is likely to reduce maintenance costs.

Proposed role for the NSP to maintain the system strength

In contrast to affected generators, NSPs are able to consider a range of issues associated with low system strength and would be well placed to develop solutions that best address all the issues being experienced. In addition to generator performance standards, NSPs will be considering their own low system strength protection and voltage control issues, and will be able to coordinate investment decisions across all of these requirements. Thus, requiring NSPs to manage system strength such that generators are able to meet their performance standards is likely to lead to more efficient investment decisions.

Under the Commission's proposal, TNSPs would be required to provide a defined operating level of inertia (see chapter 4). Managing inertia and managing system strength are likely to be highly complementary activities, as the same technical solutions - contracting for additional synchronous generation or installing synchronous condensers - can be used to resolve both issues. Therefore, investment and operational decisions would be able to be made together in a way which allowed effective and efficient outcomes - particularly in respect of the locational dimension to service provision - to be achieved.

A requirement for NSPs to provide generators with minimum short circuit ratios would additionally be similar to their existing requirement to manage the quality of supply to all their network users, including both generators and customers. That is, the NSP is required to ensure that the quality of the voltage at generators' connection points meets the requirements of the standards in the Rules. Therefore, NSPs providing a minimum short circuit ratio to existing generators would also be consistent with NSPs' existing obligations with respect to quality of supply.

NSP cost recovery

There are two main drivers for low system strength issues: reductions in synchronous generation and the connection of new non-synchronous generation at a weak part of the system. Consequently, arrangements would need to be developed for NSPs to recover the costs associated with managing both issues.

Where the entry of a new generator would cause minimum short circuit ratios to be breached for one or more existing generators, the NSP would be entitled to recover the costs of the remedial actions from the connecting generator.

The Commission considers it appropriate to allocate this risk to the causer, ie the entering generator. Existing generators would have no way of managing this risk. There also does not appear to be any rationale for socialising the risks by having TNSPs manage them and recover the associated costs from consumers.

However, the Commission does not propose cost recovery triggered by generator retirements from the exiting generators, despite the fact that, as a causer of lower system strength, it could be argued that such generators should be responsible for its restoration.

While this argument may have some attraction, it would be impractical to implement as the associated generator may no longer be covered by the Rules as a registered participant. Also, such an obligation would be an unbudgeted cost that could incentivise existing synchronous generation to consider decommissioning their generation before the system strength gets sufficiently low to require being restored.

Works resulting from generator exit would instead be undertaken by the NSP as a prescribed service, which is to say that they would ultimately be funded by consumers.

The following, final section of the chapter sets out at a high level how the above obligations and arrangements would be implemented.

5.5 Proposed framework changes to address the impacts of reduced system strength

A revised Rules framework for the management of system strength should clearly set out the associated roles and responsibilities. This would be likely to involve:

- an obligation on NSPs to maintain a minimum short circuit ratio for existing generators
- an obligation on connecting parties to meet their performance standards and to ensure that they do not prevent any existing generating systems from meeting theirs' (or to fund the NSP's costs of remedial action).

In addition, new arrangements are also required so that AEMO is able to manage system strength in real time, to mitigate any residual risks associated with the above obligations being breached for any reason. The Commission is further considering whether it would be appropriate to introduce a minimum short circuit ratio requirement for new inverter based generation.

5.5.1 Management of performance standard issues - existing generating systems

A new Rule obligation would be placed on NSPs for them to maintain the short circuit ratio at each generating system's connection point at or above a registered value, including for credible contingencies (and potentially protected events[63]). The NSP would need to consider this obligation when both planning and operating its network.

Registration of the minimum short circuit ratio for existing generating systems

If the NSP is required to maintain a minimum short circuit ratio to existing generators, it is necessary for this minimum level to be determined. Therefore, a new Rule obligation is required for existing generators and the NSPs, in consultation with AEMO, to determine the minimum allowable short circuit ratio that should apply at

63 Protected events are being considered as part of the "Emergency Frequency Control Schemes" Rule change, reference ERC0212. See: www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen

each generating system connection point to ensure that the generator will continue to be able to meet its performance standards.

Once this minimum short circuit ratio is determined it would be registered with AEMO in a similar manner to the registered performance standards.[64] The minimum short circuit ratio would be based on:

- the minimum system strength assumed when the generator performance standard was registered, if such a value is available; or
- the technical ability of the associated generating unit or system to meet its registered performance standards at low system strength.

Where the NSP, AEMO and the generator cannot agree on the minimum system strength that should apply at the generating system connection, an expert determination would be required.[65]

The generator would continue to be required to meet its registered generator performance standards whenever the short circuit ratio at its generating system is at or above the registered level.

5.5.2 Management of performance standard issues - connecting new generating systems

When a new generating system connects it will be necessary to ensure that it will be able to meet its performance standards and that it does not prevent any existing generating systems from meeting theirs'. In addition, it will be necessary to register the minimum short circuit ratio required for the new connecting generating system.

Determining a minimum short circuit ratio for the new generating system

A new Rule would be required to oblige the NSP to advise the prospective generator of the expected minimum system strength at the connection point at the time of the connection application. Schedule 5.2.4(e1)(1) currently requires the NSP to provide the highest expected system strength (ie single phase and three phase fault levels) at the connection point with the generating system not connected. This clause should be amended to also specify the minimum system strength to which the generator would be required to continue to meet its registered performance standards.

When the connecting generator would be unable to meet its performance standards at the minimum system strength specified by the NSP, the generator would need to negotiate with the NSP so that either it installs its own synchronous condenser or the

64 Under Rule 4.14, AEMO is required to maintain a register of generator performance standards. These performance standards are agreed between the NSP and generator at the time of connection and can be amended from time to time following the agreement of the NSP, the generator and AEMO.

65 The role of the expert would be similar to that in clause 4.16.7 where an expert was required to determine the performance standards that should apply to an existing generating system.

NSP increases the system strength. In either case, the costs would be recovered from the connecting generator.

Doing no harm to existing generating systems

In addition to considering its own performance standards, a connecting generator would also be required to consider the impact of its generating system on the ability of existing generating systems to meet their registered performance standards.

A new obligation is therefore needed to require a connecting generator to improve the system strength at its connection point such that it can meet its performance standards and allow existing generators to meet theirs'. This could be achieved by either:

- the new generator installing a synchronous condenser; or
- the NSP installing a synchronous condenser, with the costs recovered from the new generator.

The specification of the synchronous condenser would need to be determined as part of the connection negotiations for the new generating system.

Registration of the minimum short circuit ratio

The minimum system strength that was specified by the NSP, and subsequently agreed to by the generator, would be specified as the minimum short circuit ratio and be the registered system strength and form the basis for the generator's registered performance standards.

5.5.3 Real-time management of system strength by AEMO

There is additionally a need for arrangements to be introduced to allow AEMO to manage system strength in real time, in order to mitigate any risks arising where the obligations described in the preceding sections fail to ensure that system strength is maintained to a sufficient level.

Monitoring of system strength

Clause 4.6.1 of the Rules currently requires AEMO to calculate the system strength during normal operation of the power system, and in anticipation of all credible contingency events, so that AEMO can identify any locations in the power system where the system strength exceeds the ratings of the relevant circuit breakers.

This clause needs to be amended so that AEMO would also be required to identify the locations in the network where the system strength was below, or was likely to be below, the registered minimum short circuit ratio at a generator connection point. This would include for system normal, credible contingencies and potentially for protected events.

Maintaining system security

There is a risk to system security when the short circuit ratio at the connection point for a generating system is below the registered performance standard for that generator. This risk needs to be managed by:

- constraining the output of the affected generating systems to a level that mitigates the risks to system security;
- advising the NSP of the low system strength, to provide an opportunity for it to restore the system strength where this is possible; or
- AEMO directing a registered participant, such as the NSP or a generator, to take an action that would increase the system strength at the affected generating systems.

5.5.4 Minimum technical requirements for inverter based generation

The ability for inverter based non-synchronous generation to be able to operate at low short circuit ratios will become increasingly important as the system strength decreases and the penetration of this type of generation increases.

Therefore, the Commission is considering including an obligation in the rules for new inverter based generation to be capable of operating at a given short circuit ratio. This obligation would be expected to reduce the need for investment in services to increase the system strength as existing synchronous generation is progressively replaced by inverter based generation.

6 Lodging a submission

The Commission is inviting written submissions on this directions paper. Submissions are to be lodged online or by mail by 20 April 2017 in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on rule change requests. The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this project should be addressed to Sebastien Henry on (02) 8296 7800.

6.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the relevant project reference code as follows:

EPR0053 – System Security Market Frameworks Review

ERC0208 – Inertia Ancillary Services Market

ERC0214 – Managing Power System Frequency

ERC0211 – Managing Power System Fault Levels

Comments made in submissions that do not reference a particular project code will be treated as comments that apply to all and any of the rule change requests and the Review.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

6.2 Lodging a submission by mail

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Or by Fax to (02) 8296 7899

The envelope must be clearly marked with the relevant project reference code, as above.

Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter.

If this confirmation letter is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

Abbreviations

AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
APR	Annual Planning Report
DNSP	distribution network service provider
ENA	Energy Networks Association
FCAS	frequency control ancillary service
FFR	fast frequency response
FOS	Frequency Operating Standards
FPSS	Future Power System Security
NEM	National Electricity Market
NER or rules	National Electricity Rules
NSA	network support agreement
NSCAS	Network Support and Control Ancillary Service
NSP	Network Service Provider
NTNDP	National Transmission Network Development Plan
RAB	Regulated Asset Base
RIT-T	regulatory investment test for transmission
RoCoF	rate of change of frequency
SCR	short circuit ratio
STPIS	System Target Performance Incentive Scheme
SVC	static VAr compensator
TNSP	Transmission Network Service Provider

A Summary of submissions on consultation paper

(references are to the direction paper, unless otherwise noted)

Stakeholder	Comment	AEMC response
Assessment approach		
EnergyAustralia	Due to the suite of technical reviews ongoing, there is a risk that the Rule changes could lead to sub-optimal solutions being implemented and could lead to rule changes having to be unwound. Pg 2	The AEMC has an extensive work program which includes the System Security Market Frameworks Review and related rule changes. The Commission initiated this review as a vehicle to coordinate the assessment of the range of inter-related issues and develop appropriate recommendations for future policy changes. The AEMC's System Security Market Frameworks Review draws upon AEMO's Future Power System Security Program and other relevant review s and work streams on foot. The AEMC is working closely with AEMO during this work.
Ausgrid	It is important to ensure the outcomes of the review are also applicable and appropriate for the broader NEM (not just SA) with the different installation generation capacities. Pg1	The AEMC's work program is focused on addressing issues and framing outcomes for the entire NEM.
Major Energy Users	Concerned that AEMC review is too limited in its scope. The consultation paper seems to imply that approaches for providing reliability are not elements to be considered when assessing security.	Issues associated with NEM system reliability will be addressed separately as part of the Reliability Standard and Setting Review which will commence in March 2017.
NEO assessment		
EnerNOC	The challenge is to set up a framework in which: these services are defined in technologically-neutral terms, so that many participants, including unforeseen new entrants, can compete to supply them; and AEMO can procure a	The directions paper proposes a two-stage framework consisting of an immediate and subsequent package to procure inertia and FFR. The packages have been assessed on a range of principles including the impact on competition as well as: risk allocation;

Stakeholder	Comment	AEMC response
	near-optimal combination of these different services to meet system needs efficiently. Pg14	certainty vs. flexibility and technology neutrality (see section 5.2 of the interim report, 15 December 2016). As FFR technologies mature, co-optimisation of inertia and FFR services should achieve the least cost option for consumers.
Hydro Tasmania	Supports the Assessment Principles in section 3.4 and believes it is highly important to have a good framework for assessing options to ensure objectivity is maintained. Pg4	The Commission's principles used to develop the options and develop its proposed two stage approach is set out in section 5.2 of the interim report, 15 December 2016.
Energy Networks Association	Recommends that any proposal to manage RoCoF should be technology agnostic, and should attempt to minimise costs, for the benefit of all consumers and market participants. This would allow the use of synthetic inertia or other alternatives when it is economical. Pg5	The Commission have assessed a range of different options to deliver system security services against a number of guiding principles to ensure the best outcomes for consumers: risk allocation; certainty vs. flexibility, technology neutrality and competition. (see section 5.2 of the interim report, 15 December 2016).
Clean Energy Council	The AEMC must position the market rules appropriately to ensure that technologies such as FFR or synthetic inertia from wind turbines are contributing to power system security. This can only be achieved through the appropriate specification of standards that focus on the problem, not a solution. Pg7	The Commission initiated this review as a vehicle to coordinate an in depth assessment of the range of inter-related issues including the integration of new technologies into the framework. (see section 2.2 of the interim report, 15 December 2016).
Major Energy Users	Concerned by suggestions that AEMO could establish contracts with generators to provide additional services. Limited competition resulting from increasing penetration of asynchronous generation displacing synchronous generation needs to be considered. The impact of renewables and the impact on the supply and cost of raise and lower FCAS services also need to be considered. Pg2-4	The directions paper proposes a two-stage framework consisting of an immediate and subsequent package to procure inertia and FFR. The packages have been assessed on a range of principles including the impact on competition as well as: risk allocation; certainty vs. flexibility and technology neutrality. (see section 4.1)

Stakeholder	Comment	AEMC response
Reduced system inertia and high RoCoF		
Stanwell	It appears from AEMO's work that inertia is the most important characteristic that is missing from non-synchronous generators and that policy makers should prioritise regulatory frameworks to incentivise the provision of inertia. Pg3	The aim of the Review is to consider, develop and implement changes to the wholesale energy market frameworks to facilitate the transition to increased levels of non-synchronised generation while maintaining security of the system. Provision of inertia and creating effective incentive frameworks are central to this. The AEMC is working closely with AEMO and its FPSS program.
IES	• The distinction between a regulated requirement and a technical capability will become increasingly important if there is an incentive to be capable of withstanding high RoCoFs. One option could be to provide a financial reward for being capable of withstanding high RoCoF events (or a penalty of not being able to). This would provide an incentive for generators to be designed and installed according to these requirements. Pg1 • To mitigate a decrease in power system inertia options are: regulate a specific regional (or NEM-wide) requirement for power system inertia, leading to an inevitable curtailment of low-SRMC renewable energy generation; or enable FFR services to compensate for the decrease in power system inertia. Pg3	• The distinction between a regulated requirement and a technical capability has been considered by the Commission. It is noted that generator and loads have a range of withstand capabilities. Service providers contracted would need to withstand RoCoF at least at the targeted RoCoF limit. (see section 4.2) • The Commission is also considering cost recovery provisions. Costs could potentially be recovered from generators based on different characteristics to shift behaviour or drive investments towards a more secure operating system. (see section 4.2) • In order to allow for variable system conditions and the unknown, but potentially limited, RoCoF withstand capability of some generating units, and the prescribed process may need to incorporate an additional margin of inertia when determining the required operating level. (see section 4.2) • The Commission considers that a long-term solution to managing frequency in a low inertia system, should anticipate the use of FFR technologies.

Stakeholder	Comment	AEMC response
System strength		
Ausgrid	Low system strength could result in the need for investment in replacement/readjustment of affected protection systems and primary network. This will be pertinent in cases where fault levels are not far above the maximum expected load, and difficult topology can make a protection upgrade not possible or cost effective in addressing the discrimination and clearing time requirements. Pg2	The review aims to both identify and assess possible solutions to the issues caused by decreasing system strength and also consider the interaction between these and the potential options for managing frequency. This includes a consideration of impacts on protection systems, voltage control and generator performance standards.
Australian Energy Council	If the generator who invests in providing improved system security cannot exclude others from benefitting from the service and all those connected to the network benefit from the service at the same time then the service that enhances system security cannot be efficiently provided by a competitive market. These services should be procured by the operator or network, to increase investment and continue current voluntary practices. Pg3	The Commission considers that the procurement of inertia and FFR services by TNSPs represents a practical and effective approach to the management of system frequency issues. As part of the subsequent package of measures, the Commission is proposing the introduction of a regulatory incentive framework to guide TNSP investments. (see section 4.3)
SEAGas	Low power system strength is an issue that must be addressed at a local network level but has the potential to expose the broader network to outages due to mal-operation of protection equipment, absent appropriate action. A continuing shift towards asynchronous generation is likely to further degrade system strength, in turn increasing the threat to overall system security. In their current form, access standards do not appear to ensure that adequate system strength is maintained; and there is a pressing need to address the fact that no party is currently responsible for setting fault levels and managing system strength within acceptable limits. Pg3	Access standards and the ability of generators to meet their performance standards with reduced system strength is discussed in the directions paper. Under the proposed approach, for the generating units to be able to meet their performance standards, it is proposed that the relevant NSP be required to restore the short circuit ratio to at least the minimum level considered at the time of the connection process.
Hydro Tasmania	• The key issues with low power system strength are:	• Currently the NSPs are responsible for the provision and

Stakeholder	Comment	AEMC response
	Increasing changes in voltage for changes in reactive power; Short circuit ratios (SCR) falling below design levels of power electronic interfaced equipment such as HVDC, solar PV and wind. Performance of traditional protection systems may be compromised by being unable to discriminate different scenarios/events or detect faults at all and therefore not operate as designed; and Quality of power supply such as voltage flicker and harmonics being more prevalent and cause fatigue or damage to equipment. Pg7 • How fault level and SCR is calculated, measured and applied to power electronics needs to be considered as technologies develop. Pg7	operation of the protection systems for their networks. The Commission proposes that this remain the case and highlights the importance of NSPs coordinating planning of their networks. • The directions paper identifies a number of changes to the rules surrounding the minimum SCR for existing and new generating systems.
Energy Networks Association	Of concern are: Reduced fault levels which can increase the operating time, and may cause mal-operation of protection systems; Power Quality issues such as voltage stability, flicker and harmonics which can be exacerbated by low power system strength; Power System equipment may be affected by low power system strength. Pg3	The Commission has identified and discussed these concerns and their possible impact in chapter5.
Engie	As fault levels decrease due to retirement of synchronous generators, remaining generators may find that the consequential increase in the magnitude of voltage disturbances during system faults is beyond their capability to withstand. Resulting in remaining generator being suddenly potentially non-compliant with its generator performance standard obligations. Pg2	The ability of generators to meet their performance standards with reduced system strength is discussed in the directions paper. Under the proposed approach, for the generating units to be able to meet their performance standards, it is proposed that the relevant NSP be required to restore the short circuit ratio to at least the minimum level considered at the time of the connection process.
SA Government	• Poor voltage stability and low Short-Circuit Ratio will result in PEC devices struggling to stay connected to the network during a nearby fault. These same factors also make it difficult for such devices to achieve steady state in	

Stakeholder	Comment	AEMC response
	system normal conditions. Pg8 • It is becoming increasingly important to determine what minimum fault levels need to be maintained at connection points and HVDC links to meet system performance requirements. There are also concerns around 'weak' systems e.g. Protective relays unable to distinguish between system normal load current and fault current; Greater risk of DC/AC converters not remaining operational through network faults; Inability to achieve steady-state stability during normal system operation conditions and slow rate of recovery. Pg9	
Characteristics of services		
EnerNOC	The supply of inertia is not the exclusive domain of thermal generators. Some loads also provide natural inertia in just the same way: as angular momentum in synchronous rotating machines (i.e. large motors). For example, paper milling, mineral processing, and mining industries all employ large motors that can contribute natural inertia. Synchronous condensers do the same. Pg14	The use of synchronous condensers for the provision of inertia is considered by the Commission as a possible solution built by TNSPs. The Commission also notes that mechanical loads may also provide inertia. These solutions will be included as possible options to be pursued by TNSPs. (see section 2.2)
	To manage high RoCoF conditions, we believe the NEM needs to source faster frequency response resources, and procure them through a transparent market based mechanism. Pg1	As part of the subsequent package, the Commission is proposing the development of a market for FFR which would allow for co-optimisation with the provision of energy. (see section 4.3)
IES	In addition to existing synchronous generators, inertia could be supplied by synchronous condensers or flywheels. Literature has also suggested the possibility of extracting synthetic inertia from double fed induction generator (DFIG) wind turbines. FFR could be supplied by curtailing generator output (to enable both raise and lower), battery storage,	The Commission notes the potential use of all of these technologies as capable of providing system frequency control services. (see section 2.2) The use of synchronous condensers for the provision of inertia is considered by the Commission as a possible solution built by TNSPs. The Commission is also proposing the development of a market for FFR which would

Stakeholder	Comment	AEMC response
	central management of loads, or loads carefully tuned to respond appropriately to frequency events. Other FFR sources are likely to emerge if there is a financial incentive for development to take place. Pg3	allow for co-optimisation of the provision of FFR with energy, inertia and other FCAS. (see section 4.3) The Commission is also proposing use of TNSP contracts to procure FFR and obligations on generators to have FFR capability. (see section 4.2)
Roles and responsibilities		
EnerNOC	Supports a standard for RoCoF which should be set by reliability panel. Pg15	The Commission is reviewing the need for a fixed standard on RoCoF. A RoCoF limit that is permitted to vary over time in accordance with changing system conditions is more likely to result in an efficient outcome by optimising the required level of inertia in accordance with changing system conditions. (see section 4.2) Classification of protected events may require a specific limit on RoCoF.
Australian Energy Council	• A new requirement for a RoCoF standard should be carefully weighed against other options to control frequency such as constraints, the procurement of inertia or FFR. Ultimately to maintain a secure system, the post contingent frequency needs to remain within (or quickly revert to) the FOS. Pg2 • There may be merit to limiting RoCoF in a transparent and predictable fashion when circumstances require it. The protected event classification could be useful for such situations when severe weather events are predicted in areas with high RoCoF and vulnerable infrastructure. Either under a protected event or a contingency re-classified from non-credible to credible, and then a RoCoF constraint could be used to mitigate risk to the system. Pg3	A framework for the development of a protected event category is discussed in the AEMC's draft determination for the emergency frequency control scheme rule change.
Stanwell	If AEMO can already estimate RoCoF then AEMO can already determine whether a contingency would lead to a	The Commission is reviewing the need for a fixed standard on RoCoF. A RoCoF limit that is permitted to vary over time in

Stakeholder	Comment	AEMC response
	breach of the FOS. As AEMO already manages the system to stay within the FOS it appears that a RoCoF standard may be a superfluous subset of the FOS. Pg5	accordance with changing system conditions is more likely to result in an efficient outcome by optimising the required level of inertia in accordance with changing system conditions. (see section 4.2)
IES	This standard ought to state that the maximum RoCoF must be at least equal to the minimum access standard for new generators in the NEM; however it may be appropriate for the maximum RoCoF to be more than this. The imposition of a NEM-wide RoCoF standard might be become complicated due to the varying technical abilities of existing generators. Pg2	
SEAGas	Supports a standard for RoCoF which should be set by reliability panel. The standard should be designed to operate by limited RoCoF during any: credible contingency event and any “protected event” a level that would avoid tripping generation or load; and a non-credible contingency event to ensure UFLS schemes remain effective and to avoid potential damage to equipment. Pg4	
Hydro Tasmania	Supports a standard for RoCoF. Frequency for credible events should still always be maintained within the FOS; the FCAS market should address this but the system needs to cater for the potential of a cascading effect from RoCoF being too high. A regional standard should apply and a limit/constraint equation could be developed to manage RoCoF to acceptable limits for each region. The constraint equation(s) could then be managed by AEMO in central dispatch via NEMDE. Pg8	
Engie	Rather than attempt to define a RoCoF standard, the security objective can be expressed as a requirement to maintain the post contingent power system frequency to within the frequency operating standards, taking into account the	Permitting AEMO to vary operational arrangements for the management of system security may be more optimal as the tolerance of the system to RoCoF varies under different system

Stakeholder	Comment	AEMC response
	assessed level of frequency response to disturbances inclusive of inertia and frequency control services. This approach enables AEMO greater degrees of freedom to call on inertia and frequency control services in combination to maintain the frequency standard. Pg3-4	conditions.
Clean Energy Council	• Setting a system standard for RoCoF must account for a range of factors including: Protection settings on embedded generation and across the network; withstand capability of older conventional generation (inverter connected generation has a high withstand capability); Potential costs and market impacts (from inter-regional trade for example) from limiting RoCoF to a tight standard, and the potential implication for investment in new generation technologies going forward. • The establishment of tight RoCoF standards would likely have significant ramifications for the operation of the power system and lead to sub-optimal market outcomes so should be avoided if unnecessary. Pg6	The limit on RoCoF at any particular point in time is likely to be principally determined by the generating unit with the lowest withstand capability. If that particular generating unit has a much lower withstand capability than other generating units, then the RoCoF limit is likely to be much higher, and consequently the level of required inertia lower, in circumstances when it is not online.
SA Government	• A system standard for RoCoF may assist in the active management of power system security and can be used to clarify the guidelines for ancillary service providers on how to meet such standard. • Acceptable durations of any deviations from the normal operating range would be determined by system studies. • It may be desirable to set a different operating range for an islanded region compared to the overall interconnected system. • It may also be necessary to define in the Rules the	The Commission is reviewing the need for a fixed standard on RoCoF. A RoCoF limit that is permitted to vary over time in accordance with changing system conditions is more likely to result in an efficient outcome by optimising the required level of inertia in accordance with changing system conditions. (see section 4.2) The Commission also notes that the capability of generators to withstand high RoCoF could also result in economic benefits by reducing the level of inertia and FFR required to manage system frequency. (see section 4.2)

Stakeholder	Comment	AEMC response
	method of measurement of RoCoF and the means of measuring compliance. • Asset owners required to meet the new standard are best placed to determine such costs. The total combined cost will need to be taken into account and how the cost is divided between market participants' obligations and centrally procured services. Pg6-7	
System strength		
IES	The problem in SA may be adequately addressed by requiring appropriate technical standards on asynchronous installations, or at least the larger ones. A market-based solution may not be as effective here given that system strength, or lack of it, tends to be localised. Pg2	The Commission considers that the proposed immediate package including the provision of inertia by the TNSP is likely to provide benefits for system strength including: the TNSP will necessarily need to be involved in assessing the location of new synchronous devices providing inertia in order to determine the impacts on system strength. Providing a framework for the TNSP to coordinate the requirements for frequency control with system strength will assist in reducing the potential for the duplication of assets providing similar services. The Commission is also proposing that a new generator connecting to a weak part of the network do no harm to the performance of any existing generators in that network. (see section 4.2)
Hydro Tasmania	• TNSP's should manage fault levels (including minimum level) across their networks. The TNSP may need to procure services, invest in infrastructure, develop limits/constraints or a combination of all of these in order to manage system strength. • If a new connection (generator or load) attempts to connect to a weak connection point of the network which does not meet their design requirements, that customer should be responsible for the system strength to be	The Commission is also proposing that a new generator connecting to a weak part of the network do no harm to the performance of any existing generators in that network.

Stakeholder	Comment	AEMC response
	adequate for their connection. However, TNSP's should guarantee a minimum system strength (fault level) which protects already connected parties. Pg10	
Engie	One option would be that the network businesses could be required to identify the minimum fault level required across their network, and where generator retirements occur could be a competitive tender process for options that could improve the fault level to the required minimum. The network business could benchmark all tenders against the cost of a network solution, such as a synchronous compensator. Pg2	
Clean Energy Council	The management of low fault currents should be a consideration for Network Service Providers (NSP), not generators. Pg 6	The key change involved in implementing the Commission's proposed approach to addressing system strength issues will be to amend the rules to clarify that NSPs should be responsible for maintaining an agreed minimum short circuit ratio to connected generators. Generators would continue to be required to meet their registered performance standards above this agreed level.
SA Government	• Localised costs should be apportioned according to the contribution to minimum fault levels in the affected area. It is may be appropriate to place a value on inertia to maintain system stability. Depending on nominal bus voltage and the level of contribution to fault level expected by each generator at a connection point, non-contributing or partially contributing generators would be sharing the cost of centrally procured services to meet the required minimum fault level. Pg9 • As stated in the NTNDP the minimum SCR at a connection point should be 1.5-2.5. Maintaining the minimum ratios in points of low synchronous generation will be a limiting factor in the amount of wind generation	The Commission considers that to a certain extent, managing system strength will require an oversight of the network service provider and AEMO. The Commission's proposal would require existing generators and NSPs to determine the minimum allowable short circuit ratio that should apply at each generating system connection point to ensure that the generator would continue to be able to meet its performance standards. New connection generators would similarly have to agree to a minimum short circuit ratio and by connecting, not prevent any existing generating systems from meeting their performance standards. To the extent any issues arise, the connecting generator will be required to fund the remedial work undertaken

Stakeholder	Comment	AEMC response
	able to connect to those points on the network. Pg 8 • Similar to maintaining bus voltages and power factors at a connection point, connecting parties should be collectively responsible for fault levels on a continuous basis as the generation pattern changes. • AEMO would have the responsibility of determining minimum fault levels at any point on the network. Market based solutions or off- market procured services would be the most obvious options for AEMO to manage low power system fault levels. Central dispatch process in the form of constraints can be deployed; however they may not always provide the sufficient incentives for synchronous generators to remain online. In this case, network support agreements could be used to provide the necessary incentives to ensure minimum fault levels are maintained. Pg10	by the NSP.
Mechanisms to obtain system security services		
EnerNOC	• The most efficient approach for the provision of incremental inertia would be through a transparent market mechanism, similar to FCAS markets. Pg1-2 • The current FCAS markets may not properly value the potential sub-second response of IL-based FCAS, which may dampen the economic signals sent to potential IL providers and new market entrants. EnerNOC considers that a new market for FFR services would more appropriately value the contribution of IL (and other fast responding technologies) to frequency arrest and stabilisation. Pg8	The Commission considers that there are likely to be some issues with a market sourcing approach to inertia. Principally, the provision of inertia through a market sourcing approach may require generators to be notified well in advance of the relevant dispatch interval, such as through day-ahead unit commitment. The ability of generators providing inertia to influence energy price outcomes through rebidding may need to be managed, including possible restrictions on the ability of generators providing inertia to set the spot market price. (see section 4.1) The Commission is also proposing the development of a market for FFR which would allow for co-optimisation of the provision of

Stakeholder	Comment	AEMC response
	• Inertia should be considered alongside other options e.g. FFR. Co-optimisation by AEMO's central dispatch engine (NEMDE) should be the best way to determine how much of each service is required at any given time. Pg14	FFR with energy, inertia and other FCAS. (see section 4.3)
IES	The FFR market should be solved: on either a regional or NEM-wide basis, to account for the possibility of a particular region separating and becoming islanded; simultaneously with the existing FCAS market to enable a cost-effective supply (This is contrasted with AGL's suggestion of long-term contracts, which will become costlier). This market incentivises the provision of inertia from incumbent (and future) generators, which are (and will be) providing a valuable commodity and incentivises the provision of FFR from all market participants. Pg 3	As part of the Commission's proposal, a number of defined network areas would be determined. Each of the defined network areas would be assigned with a required operating level of system inertia to maintain secure operation of the network area as an islanded system. Defined network areas may consist of single NEM regions or sub-regions. It is expected that a future market for FFR would also require defined network areas. (See section 4.2)
Hydro Tasmania	• A reduction in contingency size by load tripping and/or SPS schemes can very effectively manage RoCoF and frequency deviations for both credible and non-credible events. Pg10 • It is essential that new mechanisms allow for the procurement of services (new and existing) which assist in managing system security. Services relating to system frequency for credible contingency events should consider all the variables that affect system frequency as outlined, including the concept of injected energy. Mechanisms need to exist for the cost recovery for all aspects that can manage system frequency (and RoCoF).	Part of the Commission's immediate package of measures is a framework for TNSPs to contract with third party providers of FFR services. Contracts would provide a means for the development and trialling of FFR technologies. (see section 4.2)
Engie	The mechanism would need to provide a sufficiently strong signal for a synchronous generator that otherwise would not have been run, to decide to come online. Pg6	The Commission considers that, in order for the TNSP to meet the required operating level of inertia, it may need to contract with multiple potential third party providers to make sure that the level

Stakeholder	Comment	AEMC response
		can be met at any given time. Payments required under these contracts will likely need to be sufficient to make the generators competitive with other generators in the dispatch merit order. (see section 4.2)
Origin Energy	If the rate of withdrawal of synchronous generation is such that the required minimum level is likely to be breached, then the establishment of long term incentives for the provision of inertia may be warranted. Pg 2	The Commission considers that the procurement of inertia and FFR services by TNSPs represents a practical and effective approach to the management of system frequency issues. As part of the subsequent package of measures, the Commission is proposing the introduction of a regulatory incentive framework to guide TNSP investments. (see section 4.3)
Generator obligation		
Stanwell	A technical obligation on participants has numerous advantages including appropriate allocation of risk and accountability for investment decisions; doesn’t give rise to inefficient signals; is on a technology neutral basis etc. Pg4	The Commission does not propose to apply an obligation on generators to provide inertia. This is discussed in section 3.1 of this paper. However, the Commission considers that many non-synchronous forms of generation already have the ability to provide a fast response to frequency deviations. It is likely that an obligation on non-synchronous generators to provide some form of FFR capability would not be an onerous requirement and would likely result in a number of long term benefits. (see section 4.2)
Energy Networks Association	• Schedule 5.1.8 of the NER could be expanded to provide TNSPs with explicit responsibility for implementing FFR schemes, or for providing other forms of support or services to manage RoCoF. Pg 6; • An obligation should be placed on all new generators to contribute to inertia and system strength. If cannot meet identified obligations, the asset owner could invest in additional plant to meet their obligations e.g. synchronous condensers or synthetic inertia; or contract another market participant to provide these services on their behalf. Pg6	
EnergyAustralia	New design standards for intermittent generation to provide inertia or FFR, however this would raise additional issues if applied retrospectively to existing intermittent generators, or	

Stakeholder	Comment	AEMC response
	alternatively would potentially act as a barrier to entry if it was only applied to new entrants. Pg3	
Tender contract procurement		
EnerNOC	• Not supportive of AGL's proposed inertia "market" as a standalone solution to address the challenge of high RoCoF, and note that the proposed rule change does not describe a market, but a tender process. Pg1 • A tender contract option is a less efficient option than market based procurement, because it is less transparent, tends to require long-term fixed quantities (which is unnatural both for the buyer and the seller), is unable to be co-optimised with energy market dispatch, has no guarantee of technology neutrality, and provides no guarantee or certainty that the services have been provided at lowest cost. Pg13-14	The Commission considers that there are likely to be some issues with a market sourcing approach to inertia. Principally, the provision of inertia through a market sourcing approach may require generators to be notified well in advance of the relevant dispatch interval, such as through day-ahead unit commitment. The ability of generators providing inertia to influence energy price outcomes through rebidding may need to be managed, including possible restrictions on the ability of generators providing inertia to set the spot market price. (see section 4.1) The Commission is also proposing the development of a market for FFR which would allow for co-optimisation of the provision of FFR with energy, inertia and other FCAS. (see section 4.3)
EnergyAustralia	• It remains to be seen whether the proposed market would provide the correct market signals to ensure inertia is sufficient and available and costed appropriately. • Market concentration of inertia providers would have the ability to increase costs to the point that an inertia market is a less optimal solution to system security. Such concentration could also increase as more synchronous sources exit the market and increased concentration occurs. Pg5	The Commission considers the issues raised by EnergyAustralia in its paper and agrees that the physical characteristics of the supply of inertia may present a number of issues which may inhibit the effective integration of inertia into the existing wholesale energy market dispatch process. However a market for FFR is proposed as part of the subsequent package. (see section 4.3)
Market sourcing		
EnerNOC	• A market based procurement approach is preferable. A new market might function similarly to the extant FCAS	A market for FFR has been considered by the Commission. FFR services are likely to be able to be co-optimised with the provision

Stakeholder	Comment	AEMC response
	markets. • If the current global-FCAS market is replicated, it may not solve the problems of 1) ensuring that FCAS providers are located in regions where their services are most valuable to system security, and 2) that such providers are available (able to be enabled) at times when system security requires. To achieve these outcomes, AEMO would have to apply regional constraints to the FCAS markets, which may necessitate re-thinking the default classification of the contingency risk posed by the Heywood Interconnector. Pg13	of energy through the existing energy market dispatch process, similar to the existing markets for FCAS. It is conceivable that a separate market for FFR would be an additional form of FCAS with a one second specification, including separate raise and lower services that are dispatched and settled on a five-minute basis. It is expected that a future market for FFR would also require defined network areas. (See section 4.3)
Clean Energy Council	To ensure capability to respond to high RoCoF would be to procure this service from generators, storage, load or anything else that can provide the desired response. Co-optimising this service with dispatch is the most desirable outcome. It is important that such approaches encourage both large and small participants to take part. Pg7	The Commission considers that this approach would encourage technological neutrality and competition. The establishment of a program to trial new and innovative types of FFR services may have long term benefits in developing a wider and diverse set of technologies for use in managing power system frequency. Promoting the use of FFR services may lower long term costs to consumers by cultivating a more competitive market environment.
Origin Energy	An alternative approach is to price inertia more broadly where all synchronous generators are paid for providing the service. This could allow for a more dynamic efficient outcome where generators are not only paid for the energy they provide but also their positive impact on system stability. If incorporated in the dispatch process, payments under this approach could be made through the existing market settlements. Pg2	The Commission considers that, in order for the TNSP to meet the required operating level of inertia, it may need to contract with multiple potential third party providers to make sure that the level can be met at any given time. (see section 4.2)
Engie	The incentive on offer from whatever the commercial arrangement is for inertia will need to be sufficiently large to influence generator commitment decisions. Pg5	

Stakeholder	Comment	AEMC response
Stanwell	If the five-minute settlement proposal incentivises large amounts of very fast response, this is likely to add to existing difficulties in managing system frequency. The problem will be exacerbated if this fast response is provided in a non-transparent, non-predictable manner. This is precisely what will happen if large loads and new technologies are not required to bid into dispatch or register as generators. Pg2	The Commission considers that the establishment of a program to trial new and innovative types of FFR services may have long term benefits in developing a wider and diverse set of technologies for use in managing power system frequency. Promoting the use of FFR services may lower long term costs to consumers by cultivating a more competitive market environment. This comment is also the subject of two other rule change requests currently under consideration by the AEMC, including five-minute settlement and non-scheduled generation and load in central dispatch.
NSCAS		
Australian Energy Council	The existing NSCAS mechanism provides a framework for inertia and voltage control to be procured by either AEMO or network businesses, however the NSCAS quantity procurement methodology is backward looking and does not allow for future impacts or current operations. Prior to establishing new regulatory requirements or markets for services, an examination should be undertaken of the appropriateness of existing measures to meet security challenges. Pg3	The existing economic regulatory framework for TNSPs provides a basis to design a framework through which inertia and FFR services could be obtained to address power system security issues. With some potential modifications, it represents a framework which has the potential to fully and holistically address ongoing system security issues in the short to medium term. (see section 4.1)
Hydro Tasmania	The existing NSCAS mechanism provides a framework for these services to be procured by either AEMO or TasNetworks; however the NSCAS Quantity procurement methodology is backward looking. Hydro Tasmania provides system support (NSCAS “type”) services which mask these issues in Tasmania. Hydro Tasmania also believes that the mechanism does not consider future issues therefore will not promote investment to manage emerging technical issues.	

Stakeholder	Comment	AEMC response
Cost recovery		
IES	One possible design is that all generators have an expected inertia/ FFR. If generators provide more than this, they earn; if generators provide less than this, they pay. This design would act to create strong incentives for the provision of an inertia/ FFR. An alternate design is that all generators pay for the inertia/ FFR supplied to the market. The cost recovery could be based on a generator's energy supply over a given time period, or their installed capacity. Pg4	There are a range of cost recovery arrangements that could be specified. Costs could be recovered based on different generator characteristics to shift behaviour or drive investments towards a more secure operating system. (see section 4.2)
SEAGas	SEAGas considers that a broad form of cost socialisation is most appropriate, such as the cost recovery mechanism put forward in the "Inertia Ancillary Services Market" proposed rule amendment. Pg5	The provision of inertia to meet the level of the required operating level would be a prescribed service. Forecast capital and operating expenditure associated with the provision of the service would be set out as part of the TNSP's revenue proposal for the relevant regulatory control period. Whether consumers should be required to meet the costs of inertia services needs to be explored further. Some proportion of the TNSP's costs for acquiring inertia services to meet the required level could also potentially be recovered from generators. These costs could be recovered based on different generator characteristics to shift behaviour or drive generation investments towards a more secure operating system.
Clean Energy Council	A well designed causer-pays scheme would be the most appropriate means to charge for additional system security services. However, the issues and inefficiencies that exist in the current approach used in causer-pays for FCAS services would need to be addressed. Pg7	There are a range of cost recovery arrangements that could be specified. Costs could be recovered based on different generator characteristics to shift behaviour or drive investments towards a more secure operating system. (see section 4.2)
SA Government	Cost recovery can be regarded as an insurance premium against incurring major costs if additional services are not	

Stakeholder	Comment	AEMC response
	procured and a security event occurs. Not providing inertia or FFR can be the basis for equivalence arrangements to purchase such services from elsewhere. Alternatively, each generator can be allocated a responsibility for maintaining RoCoF. The centrally procured inertia or FFR by AEMO can be paid for by all non-contributing or partially contributing generators in proportion to the shortfall by each generator not providing these services using its own assets. Pg3	
Interruptible load		
EnerNOC	• IL has the same effect as ramping up generation plant to remedy the imbalance in supply and demand, the primary difference is that demand-side IL can react much faster than generation plant, and can thus be more effective in arresting a rapidly falling frequency. Pg3 • IL can deliver its full offered quantity much faster than most generation plants, typically in less than one second. Other technologies such as energy storage have similar capabilities pg10 • Involuntary load shedding is costly, because it is unexpected and indiscriminate. This is very different from IL, in which customers are choosing particular loads with tolerably low opportunity costs, so as to compete to provide the required services to the market. It would be preferable to use a market to procure voluntary provision of the services. Pg12	The Commission notes the potential use of a range of different technologies as capable of providing system frequency control services. (see section 2.2)

B Summary of submissions on interim report

(references are to the direction paper, unless otherwise noted)

Stakeholder	Comment	AEMC response
System strength		
S&C Electric	Some battery energy storage system power conversion systems possess short term overload functionality that enables the battery energy storage system to contribute to fault currents at approximately 200 % of nominal output for short periods (typically up to 5s), however this is a limited response in the context of a much larger power system, but may be a useful contribution in some locations. (p7)	The Commission acknowledges that various technologies are capable of providing fault current. The Commission’s proposed approach to address issues associated with system strength is technologically neutral - there is no technological restriction on providers of system strength.
	A battery energy storage system is a highly effective method of dynamically regulating voltage through the injection of real and or reactive power, depending on what is most suitable in any given situation. (p7)	The Commission acknowledges that various technologies, including batteries and inverters, are able to provide services that assist with the maintenance of the system.
	It is likely that only network operators and AEMO will have the necessary network or system oversight to properly manage fault levels and as this becomes an increasing issue, it will be critical that the responsibility to maintain fault levels should be clearly assigned to specific system actors (p7)	The key change involved in implementing the Commission's proposed approach to addressing system strength issues will be to amend the rules to clarify that NSPs should be responsible for maintaining an agreed minimum short circuit ratio to connected generators. Generators would continue to be required to meet their registered performance standards above this agreed level.
Energy Networks Australia	The ENA notes the AEMC’s concerns about the decrease in system strength in regions of the NEM. Although a technology neutral framework is supported, solutions which also provide system strength should be incentivised where it is required. (p4)	The Commission agrees and acknowledges that a solution to system strength should both be technology neutral and acquired where it is required.

Stakeholder	Comment	AEMC response
	It is also essential that inertia and its contribution to system strength are procured in such locations throughout the NEM so as to be effective in assisting with system security. (p5)	There are likely to be services to assist with both frequency control and system strength. When this is the case, the framework or mechanism for procuring these services should allow for both issues to be addressed together. Equally, this should not prevent services to assist with maintaining the frequency, such as FFR, being procured where it is the most effective solution.
RES	Combining system strength with inertia significantly constrains the market for any potential services and again becomes technology biased. System strength issues arise locally and are more appropriately managed by the network planner. (p5)	
Delta Electricity	Delta does not support the inclusion of system strength in the consideration of the design of a market mechanism for inertia services. The technical characteristics of inertia and voltage control differ significantly and it is more appropriate that separate mechanisms be employed for each service. (p1)	
SA Government	Looking at system strength as a separate issue may be more prudent as it will dictate the option of procurement in certain cases. (p7)	
AEMO	When assessing different potential options for managing system inertia challenges it is also important to consider system strength. However, any determination regarding inertia need not fully address system strength issues, so long as any inertia determination isn't inconsistent with any future system strength frameworks. (p5)	
SA Government	System strength needs to be addressed not just as new generation connects but also as the conditions of the power system change. (p4)	The Commission's proposal would require existing generators and NSPs to determine the minimum allowable short circuit ratio that should apply at each generating system connection point to ensure that the generator would continue to be able to meet its performance standards.
	System strength in SA may be exacerbated by the connection of new inverter connected generation. (p7)	

Stakeholder	Comment	AEMC response
	A standard for minimum fault level contribution should be based on the premise that any new connection should not rely on the strong characteristic of a point in the network to meet performance standards. (p7)	New connection generators would similarly have to agree to a minimum short circuit ratio and by connecting, not prevent any existing generating systems from meeting their performance standards. To the extent any issues arise, the connecting generator will be required to fund the remedial work undertaken by the NSP.
AEMO	As system strength can also be exacerbated by the connection of multiple PEC connected generating units in close proximity, the minimum access standard could be amended to require connecting parties to not cause any existing network users to not meet their performance standards. (p6)	
	This places the responsibility on the party causing the problem but provides potential for the most efficient solution if the connecting party and a third party provider can agree on commercial terms for a central solution. (p6)	
	A draft determination of system strength could come after a determination on FFR and inertia. (p5)	Noted
	There is a fundamental level of system strength which is an essential service, required by all participants, all the time. (p6)	
	System strength could reasonably be seen as a network service. If it is viewed as a network service, an obligation could be placed on NSPs to maintain some minimum level of system strength. (p6)	The Commission considers that the existing NER place the obligation for maintaining the operation of the network protection systems and the control of the network voltage on the relevant NSPs.
	Generator performance standards could be reviewed to improve the overall resilience of the future power system to operate in weaker systems. This would lead to modifications of converter control settings for new power electronic	The Commission is considering this issue further.

Stakeholder	Comment	AEMC response
	converter connected plant. (p7)	
	Any system strength solution needs to have a locational signal due to the geographic nature of system strength issues. (p7)	The responsibility for maintaining system strength will account for the locational variability of system strength.
Generator obligation		
Reach Solar	• Generator obligation should be prescribed in the generator performance standards. It's possible that plant is not capable of accommodating change either technically or commercially. Additionally, differentiation should be made for non-market, semi-scheduled and scheduled participants. (p6) • A generator obligation would not incentivise new solutions. FFR should be incentivised, not set as an obligation using a modified FCAS market. (p6)	The Commission considers that a generator obligation to provide inertia is likely to be an inefficient solution to system security issues. See section 3.1 for more discussion on the generator obligation option. The Commission does consider that there is value in requiring new generators to install the capability to provide FFR where it is technologically possible. This obligation is proposed to only apply to new generators. (see section 4.2)
S&C Electric	Requiring existing generators, both conventional and renewable to retro-fit additional frequency support will dramatically impact on the economics and operation of the existing plant. (p5)	
Infigen Energy	The procurement of inertia and FFR through generator obligation would likely provide a high guarantee of system security, however this centralised planning approach would be a stark contrast to current practice in the NEM. Risks would be placed upon central planners and operators to ensure there's not an over or under supply of services. The approach would likely be the least efficient economically as all participants attempt to enter a service market that they may not have expertise in. Additionally, there would be a distinct lack of short or long-term signalling to the market	

Stakeholder	Comment	AEMC response
	concerning the improvement or deterioration of system security through time. (p4)	
EnergyAustralia	Generator obligation for new entrants could be a significant barrier to entry. (p4)	
Delta Electricity	Generator obligation options are less transparent and less competitive forms of a market based option which could create substantial inefficiencies for the system and risks for project proponents. A lack of transparency will reduce competition and, depending on the generator obligations, could lead to over investment in services. (p2)	
	Any revision of the obligation of generators would create the risk that generators would need to construct additional physical plant to supply the service or contract for additional services. This creates substantial uncertainty for a generator that would be impossible to manage and plan for. (p2)	
AEMO	Mandatory standards for new entrants to be capable of providing services such as FFR may aid the transition to market based solution in the future. (p3)	
HydroTasmania	Believes there is value in requiring new generators to have enhancements such as FFR (p4)	
Australian Energy Council	To prevent the occurrence of conflicting dispatch outcomes this obligation could vary in proportion to generation capacity online and should not apply to generators who are offline. (p3)	The Commission considers that if generators were obligated to provide inertia based on their generation output, it would not provide for situations where generation in a region is very low due to distributed energy resource output, high interconnector imports and/or low demand. For this reason and others, the Commission does not consider an obligation on generators to provide inertia will be sufficient to maintain the security of the power system. (

Stakeholder	Comment	AEMC response
		see section 3.1)
Market based solution		
Major Energy Users	Market based solutions might deliver efficient outcomes if there is sufficient competition, however competition amongst synchronous generation is falling. South Australia for example, is likely to face significant market power issues. (p2)	The Commission is not proposing to introduce a market approach to inertia. The directions paper proposes a two-stage framework consisting of an immediate and subsequent package to procure inertia and FFR. The packages have been assessed on a range of principles including the impact on competition as well as: risk allocation; certainty vs. flexibility and technology neutrality. (see section 4.1) The Commission considers that there are likely to be some issues with a market sourcing approach to inertia. Principally, the provision of inertia through a market sourcing approach may require generators to be notified well in advance of the relevant dispatch interval, such as through day-ahead unit commitment. The ability of generators providing inertia to influence energy price outcomes through rebidding may need to be managed, including possible restrictions on the ability of generators providing inertia to set the spot market price. (see section 4.1) The Commission is also proposing the development of a market for FFR which would allow for co-optimisation of the provision of FFR with energy, inertia and other FCAS. (see section 4.3)
Energy Networks Australia	Market frameworks should encourage the utilisation of existing potential resources, such as these assets where it is technically feasible and efficient to do so. (p5)	
Infigen Energy	The introduction of new inertia and FFR services should use market based procurement and pricing mechanisms, however along with existing frequency markets, should be critically assessed for market failures and inefficiencies as a first step measure. (p3)	
Hydro Tasmania	The market solution may ultimately drive the most efficient outcomes however this approach would a medium to long term solution. (pp2-3)	
Origin Energy	Origin is supportive of a market based approach. (p2)	
EnergyAustralia	We would have concerns around introducing an FFR market or requirement when its effectiveness is not clear. We wish to avoid a situation where the proposed service adds additional cost and complexity and is either incapable of meeting the requirements to arrest a frequency deviation, or is not required due to other market solutions or AEMO actions. (p2)	

Stakeholder	Comment	AEMC response
S&C Electric	A five minute spot market in fast frequency response or synthetic inertia seems unlikely to provide services that have to be delivered exceptionally fast. Fast response times are typically achieved through dynamic and automated services, following system frequency, which require no signal from the operator. (p3)	
Delta Electricity	Dispatched market also enables real time co-optimisation between fast frequency response services and inertia services (pp1-2)	
S&C Electric	Synthetic inertia is far harder to provide than fast frequency response and a competitive market approach for fast frequency response in the UK was shown to be quicker to bring to the system than mandated services (p4)	The TNSP would need to consider the operability of any services it procures. Part of the Commission's immediate package of measures is a framework for TNSPs to contract with third-party providers of FFR services. Contracts would provide a means for the development and trialling of FFR technologies (see section 4.2)
Energy Networks Australia	Any proposed market mechanisms should allow for the continued use of special protection schemes or equivalent where efficient (p5)	The proposal outlined by the Commission in the directions paper does not preclude network businesses from investigating the use of special protection schemes.
EnergyAustralia	Market solutions that allow for innovation in the supply of the required services should be prioritised over non-competitive mechanisms. These mechanisms should also be able to ensure that services can be procured on a dynamic basis, and only to the minimum level required. (p3)	The Commission has developed its proposed approach in accordance with the principle that competition and market signals generally lead to better outcomes than prescriptive rules or centralised planning since they are more flexible to changing conditions and give businesses the ability to meet consumers' needs as efficiently as possible.
Infigen Energy	The use of five-minute dispatch that will allow inertia and FFR to be provided more cost effectively in the future as the requirements of the system change. (p4)	The Commission proposal is in the subsequent package, FFR will be procured through a five minute dispatch process. The Commission considers that inertia will be most efficiently procured by the TNSP under an incentive framework. (See

Stakeholder	Comment	AEMC response
		section 4.3)
Origin Energy	It is unclear if a five minute market would provide sufficient certainty to facilitate adequate levels of FFR or inertia investment (p2)	The Commission has proposed a two stage framework; an immediate package where TNSPs procure inertia up to a required operating level. This is a practical approach that should provide a high degree of confidence that the required levels of inertia will be made available. The Commission also proposes the use of TNSP contracts to procure FFR and; a subsequent package which includes the development of an incentive framework on TNSPs to provide inertia where there are market benefits as well as the development of a market for FFR which would allow for co-optimisation with the provision of energy. (see section 4.1)
Australian Energy Council	If it is possible for a competitive procurement process to deliver the necessary services to maintain system security, that competitive process is likely to yield greater efficiency than a regulatory requirement which seeks to impose an obligation on generators to provide a minimum level of service. (p3)	The Commission agrees that competition and market signals generally lead to better outcomes than prescriptive rules or centralised planning. The Commission has incorporated this principle into the development of its proposal. However, the Commission considers that a proposal for TNSPs to procure a required operating level of inertia is a practical approach that should provide a high degree of confidence that the required levels of inertia will be made available.
	In the long run, inertia and energy should be co-optimised combined with market arrangements in place, where investors have the choice of providing inertia services or providing energy and not contributing to inertia. (p4)	The Commission proposes a subsequent package which includes the development of an incentive framework on TNSPs to provide inertia where there are market benefits as well as the development of a market for FFR which would allow for co-optimisation with the provision of energy, inertia and other FCAS. (see section 4.1)
	Currently, there is also an information asymmetry when examining the need for inertia services; transmission networks and AEMO are the only parties with visibility of the level of inertia in the network. So inertia does not lend itself to a competitive market structure with many buyers and sellers,	The Commission agrees that there are no natural counterparties for the provision of inertia. The demand for inertia arises as a consequence of a need to manage system frequency and maintain the secure operation of the system for the benefit of all participants. The development of a liquid secondary contract

Stakeholder	Comment	AEMC response
	all with equal access to information. (p3)	market for inertia would require the presence of counterparties on both sides of the transaction. (see section 4.1)
Contracting option		
AEMO	AEMO sees value in trials of emerging technologies. AEMO would caution against immediately committing to a prescriptive or long-term procurement options for FFR. It would be more preferable to start a series of trials which could establish the technical capabilities and benefits of FFR delivery. This could be transitioned to a market or tendering process over time. (p4)	The Commission's initial package provides for TNSPs to procure FFR services. These contracts would provide a means for the development and trialling of FFR technologies.
Reach Solar	Reach favour long-term contracts with AEMO for FFR and supports in principle, the concept of AEMO having the powers to procure the necessary services to maintain power system security (p3)	The Commission is proposing a process for TNSPs to procure FFR. The details of this option are presented in section 4.2
Delta Electricity	The task of efficiently determining the requirement and specification for a contracting option is problematic. A centralised procurement process, relying on modelled market projections, will tend to deliver an oversupply of services to cover the maximum possible future requirement. (p2)	The Commission proposes to introduce required operating levels of inertia to be provided by TNSPs. This would represent a workable level of inertia that is consistent with a range of, but not all, system conditions. As part of the subsequent package, opportunities would be available to procure additional inertia beyond the required operating level where it results in net economic benefits through the alleviation of network constraints and improvements in the power transfer capability of the network.
Major Energy Users	The report does consider an option of transmission networks providing services as part of resolving inertia and fast responses, but the MEU points out that such an option might be a regulated service or a market based service. This then creates challenges as to how these services will be paid for in order to provide the certainty of a return. (p3)	TNSPs would provide the required operating level of inertia as a regulated service in the Commission's initial and subsequent packages. TNSPs will also procure inertia under an incentive framework as a regulated service in the subsequent package.

Stakeholder	Comment	AEMC response
S&C Electric	Care is needed to ensure that contract length and contract terms are appropriate for new approaches to providing system services and don't exclude, where feasible, the opportunity to access multiple income streams, as contracts of the appropriate length and terms will facilitate the delivery of the service at a lower cost. (p2)	It is expected that TNSPs would work with AEMO and third party providers to determine the terms of contracts for the provision of FFR services. This would include payment structures and the conditions for the availability and use of the services.
Energy Networks Australia	TNSPs are well placed and willing to provide inertia and FFR services where it is technically feasible, efficient and economical for them to do so. However, as identified by the AEMC, this may require some amendment to the current regulatory framework to allow for the practical implementation of this option. (p3)	The Commission has incorporated this feedback.
	Supports the TNSP provision of inertia and system strength, when this is the most optimal solution and provided that that responsibilities are clearly defined and clarified in the existing regulatory framework. (p5)	The Commission agrees that the roles and responsibilities regarding the provision of inertia, system strength and FFR would need to be clearly outlined in a regulatory framework.
	TNSPs have the knowledge, information and requisite skills to undertake modelling and analysis of the power system. Consequently, in many circumstances, TNSPs are well positioned to evaluate and potentially provide and/or procure optimal solutions for power system security and stability in the medium and longer term. (p7)	The Commission has incorporated this feedback.
	TNSPs could reasonably extend their current role in terms of implementing FFR. In doing so, TNSPs would be able to leverage off their existing corporate capability, information management systems and forecasting capacity.	In the initial package proposed by the Commission, TNSPs would be responsible for procuring FFR which would provide a means for development and trialling of FFR technologies.
	TNSPs should not be prevented from either bidding on a case-by-case basis to provide such services, or where	In the Commission's proposal, TNSPs would undertake a RIT-T for the provision of services.

Stakeholder	Comment	AEMC response
	appropriate undertaking a RIT-T assessment prior to the building of, or procuring, a system security market service. (p8)	
Infigen Energy	Long-term procurement options, whether through a contracting process by AEMO or transmission network services providers, will not allow for participants to be flexible and make investment decisions that react to the changing nature of the system. (p3)	In developing its proposal, the Commission has considered the principle of appropriately balancing certainty with flexibility. The Commission considers that the contracting process provides a sufficient balance.
EnergyAustralia	Of the four options proposed in the interim report, contracting by either network businesses or AEMO is likely to be the least flexible option. (p3)	
RES	RES supports the view of a staged initial procurement program of limited tenor (e.g. 5 years) contracts be undertaken by AEMO of a RoCoF Support Service to assist in developing the market, transitioning to a 5 minute market. This would ensure services are efficiently procured both in terms of volume and price after the initial procurement rounds expire. (p6)	In the immediate package proposed by the Commission, TNSPs would be responsible for entering into contracts for FFR services where they could be demonstrated as a substitute for the required operating level of inertia. These contracts would provide a means for the development and trialling of FFR technologies. This enables the efficient utilisation of current resources. The subsequent package would seek to implement a market based procurement of FFR and the procurement of inertia for market benefits under an incentive framework placed on TNSPs.
Hydro Tasmania	HydroTas does not believe the network provision option is being fully exploited. A detailed examination of the appropriateness of existing NSCAS measures to meet system security issues should be undertaken. This mechanism would also be suitable for managing system strength. (p2)	
Delta Electricity	Contracting presents much higher investment risk, unless contracts are long term. However, with changing market requirements long term investments are unlikely to be efficient. (p2)	The required level of inertia procured by TNSPs would provide a high degree of certainty that the necessary inertia would be provided over the short to medium term. This would be complimented by a process through which TNSPs would enter

Stakeholder	Comment	AEMC response
		into contracts with providers of FFR.
	TNSPs will have limited incentives to drive least cost outcomes and consumers will rely heavily on the AER to determine the appropriate level of expenditure for the services procured. (p2)	The Commission considers that the RIT-T framework provides a means to adopt the most efficient and least cost approach. As part of the subsequent package, the Commission proposes to introduce an incentive framework to guide TNSP investments towards the most efficient approach to the procurement of services.
	Whilst AEMO is obligated to adhere to the National Energy Objective, the interpretation of this goal creates unnecessarily wide limits to what might be the most efficient service to procure. (p2)	In the Commission's proposal, TNSPs would be responsible for the provision of inertia and FFR as part of the immediate package.
EnergyAustralia	If the NSP approach was used in relation to inertia, further complications arise due to inertia also being capable of being provided through other technologies such as synchronous condensers. This equipment may be installed as part of network businesses network augmentations for the purpose of voltage control, required as part of their obligations to plan and operate their network in a way to reduce the risk of cascading failures for any credible or non-credible event. A corollary benefit would be the provision of inertia when the condenser is in operation. However, consideration should be given to ensuring that benefits of such installations can be captured, without market distortion from allowing monopoly asset owners to be involved in a competitive element of the market. (pp3-4)	The Commission's proposal consists of two stage process for the procurement of inertia. Initially, TNSPs would be required to procure the operating level of inertia through a NER based process. At a later stage, TNSPs would be able to also procure inertia for market benefits under an incentive scheme.
Origin Energy	It is important that we first have a thorough understanding of the magnitude of the problem including the appropriate levels of each service that must be procured. AEMO is best placed to carry out this work which would need to cover off of a number of areas including assumptions regarding market	In the Commission's proposal, AEMO would be partially responsible for determining the required operating level of inertia through a prescribed process. The prescribed process would involve a consideration of a range

Stakeholder	Comment	AEMC response
	entry, costs, and capability of new technologies for the provision of FFR and inertia, inertia and FFR requirements in an islanding scenario where a region is disconnected from the rest of the NEM; and locational system strength issues due to a reduction in the stock of synchronous generation. (p2)	of factors that are likely to influence the required level of inertia in a region, including: — the capacity and number of generating units and transmission lines in the region which would establish the size of potential contingency events — the tolerance of generating units in the region to different RoCoF levels — the availability of other frequency control services.
Other comments		
Energy Networks Australia	ENA also considers that the AEMC's approach should allow the consideration of multiple options, allow new and emerging technologies to be integrated where appropriate and establish a framework that is flexible and allows for changes in the optimal mix of services and the way that these services are procured as the system develops over time. (p6)	The Commission's proposal includes various options for the procurement of inertia and FFR. In the initial package, the TNSP would be required to procure the operating level of inertia and FFR would it could be demonstrated as a substitute. In the subsequent package, TNSPs would procure inertia for market benefits under an incentive framework and a short term market would be established for FFR.
Delta Electricity	The inclusion of system security payments in the energy price via constraints, is not favoured because it emphasises the contingency constraints rather than the value of the services. (p2)	The Commission has incorporated this feedback.
Engie	The decision to commit synchronous capacity is a significant one that would require a substantial amount of money to be justified. It is questionable whether the value placed on inertia, which has in the past had no value placed on it at all, should suddenly be priced so highly that it will be sufficient to change synchronous generator commitment decisions. (p2)	The Commission's proposal for TNSPs to procure the minimum amount of inertia would require TNSPs to maintain that a sufficient amount of inertia has been procured. The Commission considers that, in order for the TNSP to meet the level of the minimum inertia standard, it may need to contract with multiple potential third-party providers to make sure that the standard can

Stakeholder	Comment	AEMC response
		be met at any given time. (see section 4.2)
AEMO	Hybrid option 1 - NSCAS framework to identify an inertia gap with a market approach to top up the inertia in response to real time condition. This market could either be a day-ahead market or a 5-minute market. This would allow for longer term contracts with the TNSP to provide investment certainty while the additional inertia could be co-optimised with other services such as FFR and reducing the contingency size. (p4)	The Commission has incorporated consideration of these proposals in the development of its approach to procuring inertia and FFR services. (see section 4.1)
	Hybrid option 2 -Similar to the NSCAS framework where NSPs procure the baseline inertia with long term contracts and AEMO procures inertia that delivers market benefits which is not currently allowed under the NSCAS framework. (p4)	
	There should be an incentive in any inertia solution to also consider how system strength could be addressed and vice versa. (p7)	The Commission's proposal would require TNSPs to maintain system strength to a certain level. TNSPs would coordinate the provision of inertia and system strength.
Australian Energy Council	In order to elicit a supply response the revenue available to inertia providers must cover the cost of supply. In the long run, this may mean that revenue needs to cover the cost of a new investment. (p3)	The Commission has incorporated this feedback.
Origin Energy	In our view, there are likely to be trade-offs in the adoption of a five minute or contracting market. Origin suggests that the next step in the process focuses on the continued development of both models for further consideration. (p3)	The Commission's proposal is intended to allow appropriate time for the development of a market for FFR. The initial proposal would require TNSPs to contract for FFR.

Stakeholder	Comment	AEMC response
Trade-off between inertia and FFR		
Reach Solar	Reach agrees that a focus on system inertia may act as a barrier to future innovation in FFR technologies. (p3)	The current early stage of FFR technologies presents a risk that incentivising TNSPs to seek market benefits opportunities might "lock-in" the provision of inertia from network investment over the long term. Consequently, the Commission considers it appropriate that the subsequent package is developed and implemented over the medium term, which might represent a period of three or more years.
Major Energy Users	MEU considers that the solutions provided by the AEMC are too focused on “within region” solutions. (p1)	The Commission has incorporated the principle of balancing flexibility and certainty into its proposal.
Energy Networks Australia	The most optimal option may vary over time and the market framework established should be sufficiently flexible to allow this to occur while providing sufficient certainty of roles and responsibilities. (pp3-4)	The Commission has incorporated the principle of balancing flexibility and certainty into its proposal.
	Agrees that inertia and any FFR will perform differing roles in the effective management of power system frequency and that both of these services may be needed to manage future power system security. (p4)	The Commission has incorporated this feedback.
	ENA considers AEMO may be best placed to determine what option would best deliver the optimal solution and appropriate levels of inertia or FFR. (p8)	In the immediate package proposed by the Commission, TNSPs will be responsible for determining which services to procure.
RES	RES’s work in this area to date shows us that response times of less than 100ms are achievable with existing commonly utilised network hardware and communications. This shows that targeting the delay times can drastically reduce the level of FFR required for similar RoCoF outcomes. (p3)	The Commission has incorporated this feedback.

Stakeholder	Comment	AEMC response
EnergyAustralia	Any mechanisms for FFR and inertia should be both technology and participant neutral. (p3)	The Commission agrees and has incorporated the principle of technology neutrality into its consideration of various options.
Delta Electricity	The transition to increased FFR should be contingent on a thorough assessment of the performance of each type of fast frequency response technology in supporting system security. To facilitate this transition Delta supports the creation of separate markets for synchronous inertia and fast frequency response with oversight by a separate independent body. (p3)	The Commission considers the fledgling state of technologies that provide FFR, and the lack of present knowledge as to how the operation of the power system might be impacted, suggests that the implementation of new markets for the provision of FFR services may be premature at this time. A greater level of experience with using FFR services to control system frequency may be required before a service could be properly specified and a 5-minute market developed that would be able to be co-optimised efficiently with the existing energy and FCAS markets.
SA Government	FFR services can be a valuable resource to give more time to contingency FCAS to be effective. (p4)	The Commission has incorporated this feedback.
	it may be useful to assess the option to integrate the FFR service as a new product in the existing FCAS arrangements. (p6)	The Commission will give a future market for FFR further consideration.
AEMO	There may be future opportunities to co-optimise the amount of inertia procured with other services or constraints such as FFR or reducing contingency size. This would require flexibility in the amount of inertia procured and a means of comparing the marginal cost of additional services. This could be achieved through a market mechanism or contracting with a low fixed payment. (p3)	The immediate package introduces mechanisms to allow the procurement of both inertia and FFR, with the subsequent package giving effect to more sophisticated approaches to trading off the costs of these services against the costs that would arise from constraining generator dispatch in their absence.
Level of inertia		
Reach Solar	Reach considers a combination of fast acting asynchronous	The Commission considers that at present there is a minimum

Stakeholder	Comment	AEMC response
	technologies and controlled load shedding will ultimately replace the need for conventional inertia. (p3)	level of inertia that is required to maintain the security of the power system. The Commission acknowledges that there is a question as to whether this will always be the case.
TasNetworks	Inertia requirement should be based on the post contingent requirement for inertia. (p2)	AEMO would be the party responsible for conducting the prescribed process to determine the required operating level of inertia. The prescribed process would involve a consideration of a range of factors that are likely to influence the required level of inertia in a region, including: — the capacity and number of generating units and transmission lines in the region which would establish the size of potential contingency events — the tolerance of generating units in the region to different RoCoF levels — the availability of other frequency control services. The required operating level of inertia would also need to account for the fact that the contingency that occurs may be the loss of a large synchronous generating unit providing inertia. The Commission has incorporated this feedback. The Commission considers that most effective method for maintaining system security is outlined in its proposal. The relevant TNSPs would be responsible for how they procure the required level of inertia. The Commission considers that, in order for the TNSP to meet the level of the required operating level of inertia, it may need to contract with multiple potential third-party providers to make sure that the level can be met at any given time.
Energy Networks Australia	When determining the minimum inertia required for the system, contingencies that involve the loss of the largest inertia contributor should be considered. (p5)	
Delta Electricity	A conservative approach to setting the requirement for inertia and fast frequency response, which takes into account the N-1 principle and credible contingencies, should be considered if system security is paramount. (p3)	
Engie	When a generator is incentivised to come online, it will need to operate to at least its minimum operating level, and so it will cause the wholesale energy price to fall. This may prompt other generators that were previously online to decide to come offline, meaning that the inertia may again fall below the desired level. (p3)	
	Engie believes that if it is necessary to reduce one or more generators to make head room to bring an inertia unit online, the most appropriate generators to reduce are the nonsynchronous generators that are providing no inertia. This outcome could potentially be achieved through one of two possible mechanisms; constraining non-synchronous generators or paying all online generator for providing inertia and recovering the money from non-inertia providing generators in proportion to their output. (p3)	

Stakeholder	Comment	AEMC response
SA Government	It is important for industry to agree on RoCoF settings that would not adversely affect plant protection settings for generators. (p5)	The Commission will consider the RoCoF withstand capability of generators further. Improving the capability of generators to withstand high RoCoF could also result in economic benefits by reducing the level of inertia and FFR required to manage system frequency.
Costs		
SA Government	Costs of extra inertia needs to consider all market implications, such as the displacement of lower cost generators by inertia providing generators. (p4)	The provision of inertia to meet the required operating level would be a prescribed service. Forecast capital and operating expenditure associated with the provision of the service would be set out as part of the TNSP's revenue proposal for the relevant regulatory control period. There are a range of factors that could determine the manner in which the costs are divided amongst generators. Costs could simply be recovered from generators that do not provide any inertia. Costs could also be recovered from generators on the basis of the physical characteristics that cause the required level of inertia. As discussed above, the level of required inertia is influenced by the size of contingency events and the tolerance of the system to high RoCoF. As such, costs could potentially be recovered from generators on the basis of their generation output or RoCoF withstand capability. (see section 4.2)
EnergyAustralia	The roles for inertia and FFR, as well as costs for implementing these schemes, should be assessed in light of any of the above potential solutions resulting from other current system reviews. (p2)	
Reach Solar	In a short term market solution, Reach does not agree that costs should be borne state-by-state. (p7)	
Australian Energy Council	The benefits of inertia are diffused across the whole system, where investors who provide inertia cannot exclude those who do not pay for the service from receiving benefits. (p2)	
Delta Electricity	Costs should be borne by the market participants that contribute to the demand for the service. (p2)	
Generator performance standards/license		
Reach Solar	License conditions should not be included on a retrospective basis. This is likely to be considered by investors as increasing sovereign risk and dissuade new investment. (p4)	The Commission's proposal does not currently include any changes to generator registration that would require currently registered generators to adopt changes.

Stakeholder	Comment	AEMC response
Energy Policy Institute of Australia	AEMO should consider broader system impacts before granting any new application for a generation license and should either refuse the license or impose additional license conditions if that new generator connection is likely to impact on system security. (p1)	The Commission has incorporated this feedback.
	There is merit in AEMC suggestion that there could be a minimum technical standard expected of generators to either physically provide services to contract for these services. (p1)	The Commission is proposing that generators would be required to have the capability to provide FFR where technically feasible. The Commission will consider the RoCoF withstand capability of generators further. Improving the capability of generators to withstand high RoCoF could also result in economic benefits by reducing the level of inertia and FFR required to manage system frequency.
EnergyAustralia	New design standards for intermittent generation to provide inertia or FFR could be a less complex mechanism, avoiding the need to establish a new market or procurement methodology. However, there exists the risk that additional requirements could significantly increase the costs of either inertia or FFR. (p4)	
SA Government	The Division emphasises the importance of establishing a RoCoF standard including a maximum limit that all generating units can sustain. (p7)	
Engie	As noted in the interim report, it will be difficult for many of the existing generators to be able to accurately establish exactly what their RoCoF tolerance might be, other than through trial and error. A prudent approach is therefore suggested which does not retrospectively apply stringent standards on existing plant that they are unable to achieve. On the other hand, any plant that is seeking a payment for inertia under a new commercial mechanism should be required to establish that its equipment is capable of withstanding a RoCoF event at least to the targeted level. (p5)	

Stakeholder	Comment	AEMC response
S&C Electric	We note that the Hydro-Quebec approach is bespoke to their system and a great deal of work would be required in Australia to develop the required response characteristic standards. (p4)	
Energy Networks Australia	Energy Networks Australia also agrees that the ability of generators and loads to withstand changes in frequency is critical to the existing and future security of the power system and welcomes the AEMC's initiatives to further consider the appropriateness of generator performance standards. (p4)	
EnergyAustralia	EnergyAustralia considers it essential that the work into better understanding generation performance and impacts of RoCoF on system security is prioritised as a means to determining the requirements for FFR and inertia services. (p2)	
Frequency control		
Pacific Hydro	It is critical for system stability that sufficient frequency response is available within all regions and particularly in regions with less inertia. Operating a region without primary governor control enabled on units within that region means the region is being operated without any spinning reserve, because fast generator re-dispatch in response to system frequency changes is provided by primary governor control action. Spinning reserve is not provided via the market dispatch system or by the AGC – this is too slow and unlikely to correctly allocate the reserve if the dispatch is based on economic modelling alone. (p11)	The Commission is further considering frequency degradation in the NEM. The Commission considers that while addressing frequency degradation, primary governor control, the causer pays methodology and other related issues may impact upon the level of services procured to maintain system security, it is unlikely to impact the design of the framework through which these services are procured. The review is not considering the effectiveness of the FCAS framework more generally. However, there is likely to be merit in a more thorough examination of the framework to see if
	A sufficient proportion of regional primary governing control is not optional and should not be turned off, to do so	

Stakeholder	Comment	AEMC response
	significantly alters the response of the units within a region for the purpose of calculating the transfer limits. (p11)	adjustments would allow frequency to be managed more efficiently.
	The current causer pays methodology leads to undesirable outcomes with respect to measuring the actual frequency performance of plant. It ought to be removed or replaced with a mathematically correct assessment of a unit's actual frequency response. Under existing arrangements, a participant cannot implement a control system to eliminate their unit's causer pays factor as the unit is not directly measured against the reference frequency of the system. The generator can only measure and respond to the local frequency. (p11)	
	Units that provide primary frequency control within the normal operating band are performing a necessary frequency control action that reduces the amount of regulation service required. There should be no penalty for units that provide this primary control function. The separation of services between frequency standard bands should be discarded as primary response must commence within the normal operating in order for the arresting energy to contribute to reducing the rate of change of frequency. (p11)	
	To ensure good system behaviour, fast primary control action should be valued not penalised. The faster the frequency is controlled the more efficient the overall system. (p11)	
	The FCAS markets require considerable redesign so that primary control can be re-instated within a safer and up until recently a more normal operating band. (p11)	
Infigen Energy	There are several shortfalls in the current FCAS market design. These include changes in the behaviour of	

Stakeholder	Comment	AEMC response
	synchronous generators over the last 15 years, and the increased incentive to prioritise dispatch target performance over frequency support under the Causer Pays compensation structure. (p1)	
	The widening of the frequency normal operating band and the removal of the tight dead band requirements for primary governor response has resulted in a weakening of frequency control in the system and raises the risk of worsening the impact of a contingency event or not being able to survive it. (p1)	
	Under the Causer Pays system, a generator is expected to achieve its dispatch target in a linear trajectory. This system can result in generators that may ultimately be providing FCAS services or delivering good frequency service (according to the governor response) incurring higher causer pays factors (and costs) because of a non-linear trajectory. (p3)	
Clean Energy Council	The need for governor response increases in importance under high rates of change of frequency (in situations where inertia is low for example) where the speed of actioning this response is critical to arresting the frequency change. Delaying or even disabling the governor response risks a collapsing system. (p3)	
	Inertia response must be supported immediately by primary control response provided by generator governors. (p3)	
	Given the above it appears that the likelihood for increased extreme frequency events is now a design aspect of the NEM. The FCAS market's causer pays arrangements have	

Stakeholder	Comment	AEMC response
	led to a significant de-tuning of the power system. (p3)	
	If the NEM was well tuned with appropriate frequency control the view that further inertia services are required should also be questioned. It is likely that sufficient synchronous inertia exists to manage system security if it is subject to appropriate control schemes. (p4)	
	CEC believes that the focus of this review should be on revising the current FCAS arrangements and removing incentives for poor frequency control. In doing so the redesigned FCAS arrangements should look to implement fast frequency response capability in the sub-one second timeframe as a means to bring new technologies online through the revised FCAS regime. (p4)	
	The long-term interests of consumers would be best met where by resolving issues in the existing regime and expanding this regime to deliver advanced technological solutions. (p4)	
Pacific Hydro	The system stability guidelines must be understood and market mechanism must not be allowed to contradict the requirement for maintaining stable regions even when they island. (p11)	AEMO would be the party responsible for conducting the prescribed process to determine the required operating level of inertia. The prescribed process would involve a consideration of a range of factors that are likely to influence the required level of inertia in a region, including: • the capacity and number of generating units and transmission lines in the region which would establish the size of potential contingency events • the tolerance of generating units in the region to different RoCoF levels

<table>
<tr><th>Stakeholder</th><th>Comment</th><th>AEMC response</th></tr>
<tr><td></td><td></td><td>• the availability of other frequency control services.</td></tr>
<tr><td>Major Energy Users</td><td>AEMC does not consider whether increased interconnection might deliver a lower cost solution. (p2)</td><td>In the Commission proposal, TNSPs would not be precluded from considering interconnection to address system security issues.</td></tr>
<tr><td>TasNetworks</td><td>As there is only one supplier of cost effective inertia in Tasmania, a procurement/supply mechanism for inertia/FFR should acknowledge this. (p1)</td><td>The Commission will consider this further.</td></tr>
<tr><td>Energy Queensland</td><td>In addition to the power system security services proposed, the AEMC should also consider if the networks’ frequency bandwidth tolerances could be wider. (p4)</td><td>The Commission will consider this further.</td></tr>
<tr><td>EnergyAustralia</td><td>At this stage it is not entirely clear what level of substitutability FFR would have with regard to these 6 second services. This interaction could degrade the value of 6 second services, or it could lead to coordination issues given the potential for overlap between these two types of faster frequency response. (p3)</td><td>The Commission acknowledges that there are likely to be interactions between FFR and other FCAS. This will be considered further.</td></tr>
<tr><td>Engie</td><td>Engie would prefer to see constraining the power system to minimise the contingency size only used as a last resort. (p3)</td><td rowspan="3">The Commission’s proposals would not be reliant on constraining the power system to minimise the contingency size in order to maintain system security. However, the Commission acknowledges that constraining the power system for system security purposes may be the most effective solution in some circumstances.</td></tr>
<tr><td>Australian Energy Council</td><td>Constraining down generation to prevent the loss of system security should be a last resort. (p4</td></tr>
<tr><td>Infigen Energy</td><td>The use of energy market constraints that limit the rate of change of frequency, and the use of localised regulation requirements within the synchronised network has led to a substantial financial cost and impact to market participants. Infigen finds it imperative that the final framework will be able to replace these market interventions. (p4)</td></tr>
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Stakeholder	Comment	AEMC response
Engie	Engie would suggest that the FOS be revised to include consideration of a separation event due to a contingent loss of a protected interconnector, and apply a more relaxed frequency standard. (p4)	The Commission notes this comment. This would best be addressed in the upcoming review of the frequency operating standards.