Australian Energy Market Commission

REVIEW

FINAL REPORT

System Security Market Frameworks Review

27 June 2017

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Final Report

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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

The shift in our generation fleet being driven by climate change policies and technological advances is changing our energy landscape. It is transitioning from one dominated by conventional generation powered by coal, gas and hydro to one powered by renewable sources such as wind and solar. This change in generation technology has altered the operational dynamics of the power system and our need for system services to be able to keep it secure.

Many of the system services needed for power system security were provided as a matter of course by conventional generation when producing energy. Changes to market and regulatory frameworks are necessary to ensure that such services remain available for the secure operation of the power system. These frameworks need to be sufficiently flexible to facilitate and keep up with the pace of this transition across all parts of the National Electricity Market (NEM) while providing energy securely to consumers at least cost.

System security work program

The *System security market frameworks review* was initiated by the Australian Energy Market Commission (AEMC or Commission) in July 2016 to consider changes to the regulatory frameworks to support the current shift towards new forms of generation in the NEM. The focus of the review has been on addressing priority issues to allow the Australian Energy Market Operator (AEMO) to continue to maintain power system security as the market transitions.

Under the National Electricity Law, AEMO's statutory functions include maintaining and improving power system security. Consequently, the review has adopted the priorities identified by AEMO in its *Future Power System Security* program, which it initiated in December 2015. The work of the AEMC through this review has been to identify and develop the changes to market and regulatory arrangements required to address the technical issues highlighted by AEMO.

Our priorities in the review have been to develop recommendations that will result in:

- *a stronger system*
- a system better equipped to *resist frequency changes*
- *better frequency control*
- actions to further *facilitate the transformation*.

These were areas that we needed to address because they were priorities identified by AEMO, and are critical to have confidence that the system will be able to immediately respond securely to the operational dynamics brought about by the transition. In making our recommendations we have also considered how the implementation of them is best progressed, including through rule changes that have been assessed concurrently with the review.

We have received five rule change requests on matters related to the review, and these will provide the means for three of our recommendations to be put in place without the need for further implementation processes. We have already made rules in relation to the other two proposals, with new arrangements for under- and over-frequency control schemes being introduced on 6 April 2017.

A stronger system

As traditional, synchronous generators retire and are replaced by increasing numbers of non-synchronous generators connected to the power system by inverters, the system strength decreases. System strength refers to the relative change in voltage for a change in load or generation at a connection point, and low levels of system strength can jeopardise the ability of generators to operate correctly, thus threatening system security.

In order to meet this challenge, we are making two recommendations to maintain system strength while minimising the costs that will flow through to consumers.

Recommendation	How the recommendation will be implemented or further progressed
1. Introduce regulatory arrangements to require network service providers to maintain the system strength at generator connection points above agreed minimum levels, with new connecting generators required to 'do no harm' to previously agreed levels of system strength.	Draft arrangements published for consultation on **27 June 2017** as part of the draft determination made on the *Managing power system fault levels* rule change proposed by the South Australian government. Arrangements are scheduled to be finalised on **19 September 2017**.

Network service providers are best placed to develop solutions in this regard, as they will already have to consider their own low system strength protection and voltage control issues, and will therefore be able to coordinate investment decisions. Where new entrant generators would degrade the level of system strength provided to other generators, they will be required to meet the costs of remedying this.

Recommendation	How the recommendation will be implemented or further progressed
2. Consider requiring inverters and related items of plant within a connecting party's generating system to be capable of operating correctly down to specified system strength levels.	AEMO intends to submit a rule change to the AEMC by **July 2017** requesting revisions to the generator performance standards consistent with advice it has provided regarding South Australian generator licence conditions. This recommendation will be considered for implementation through the AEMO rule change request and is consistent with AEMO's advice provided in respect of South Australia.

System strength will remain relatively high in many parts of the NEM while baseload, synchronous generators operate there. In these circumstances, there may be little incentive on either the proponent or the network service provider to seek to minimise the effect of a new connection on system strength. Requiring inverters to be capable of operating at low levels of system strength could significantly reduce future mitigation costs.

Resist frequency changes

Historically, the large numbers of synchronous generators in the NEM have helped it resist sudden changes in frequency. Supply must always precisely meet demand for the frequency of the system to stay steady at 50 Hz. The physical inertia provided by the large rotating masses in synchronous generators dampen the effects on frequency of any sudden imbalances in supply and demand caused, for instance, by the loss of a major generator, load or transmission line. This buys time for additional power to be injected or withdrawn and balance to be restored.

Despite having useful characteristics that many synchronous generators do not have, non-synchronous generators, being connected to the power system through inverters, do not provide inertia, even where the power generation is the result of mechanical movement. As the generation fleet evolves, new approaches are required to resist sudden frequency changes and therefore maintain power system security.

Recommendation	How the recommendation will be implemented or further progressed
3. Place an obligation on transmission network service providers to provide minimum required levels of inertia, or alternative equivalent services, to allow the power system to be maintained in a secure operating state.	Draft obligations published for consultation on **27 June 2017** as part of the draft determination made on the *Managing the rate of change of power system frequency* rule change proposed by the South Australian government. Arrangements are scheduled to be finalised on **19 September 2017**.

The provision of inertia by transmission network service providers would offer certainty that the minimum required levels would be made available, either through investment in network equipment or by contracting with third party providers. Under network regulation arrangements, transmission network service providers have financial incentives to minimise the costs associated with meeting their obligations. They would also have the ability to coordinate inertia provision with the more locational requirements of maintaining system strength.

Recommendation	How the recommendation will be implemented or further progressed
4. Introduce a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum obligation on transmission network service providers.	Draft mechanism to be published for consultation on **7 November 2017** as part of the draft determination to be made on the *Inertia ancillary service market* rule change proposed by AGL.

Additional inertia above the minimum level associated with maintaining system strength would allow power to flow on the system in a less constrained way, potentially reducing market energy prices. However, the levels of inertia required to remove all constraints are highly variable. Consequently, using a market-based mechanism that puts a price on inertia to unlock these market benefits would allow market participants to co-optimise their provision of inertia and energy, minimising overall costs. We have identified a candidate mechanism for further development.

Better frequency control

But there are more changes that are likely to be needed to facilitate the transition. AEMO and other stakeholders have identified the need for *better frequency control*. Frequency control services will become increasingly important as a complement to, and partial substitute for, inertia.

While inertia only buys time, frequency control services rebalance supply and demand, and new technologies have the potential to provide new, faster services. However, concerns have been expressed that, before additional services are designed and implemented, the existing arrangements for frequency control need to be reviewed.

Recommendation	How the recommendation will be implemented or further progressed
5. Assess whether mandatory governor response requirements should be introduced and investigate any consequential impacts (including on the methodology for determining causer pays factors for the recovery of regulation FCAS costs).	In **July 2017** the AEMC will initiate a review into market frameworks necessary to support better frequency control: *Frequency control frameworks review*. AEMO has commissioned expert advice on the causes and impacts of deteriorating frequency control performance, for consideration by its Ancillary Services Technical Advisory Group in **July 2017**. The Commission will consider the outcome of this work and its implications through the review.

Prior to 2001, all generating units in the NEM over 100MW were obliged to have governors in operation that controlled the speed of the machines in response to changes in system frequency. With the introduction of spot markets for Frequency Control Ancillary Services (FCAS) in 2001, this requirement was removed. It has been suggested that this change has contributed to a recent decline in frequency control performance in the NEM. AEMO is currently undertaking work to further investigate the issue, which should be progressed as a matter of priority.

Recommendation	How the recommendation will be implemented or further progressed
6. Review the structure of FCAS markets, to consider: • any drivers for changes to the current arrangements, how to most appropriately incorporate FFR services, or alternatively enhancing incentives for FFR services, within the current six second contingency service; and • any longer-term options to facilitate co-optimisation between FCAS and inertia provision.	Further consideration through the AEMC's *Frequency control frameworks review* (commencing **July 2017**) and AEMO's future work program.

New technologies, such as wind farms and batteries, offer the potential for frequency response services that act much faster than traditional services, perhaps as quickly as a few hundred milliseconds. Although such Fast Frequency Response (FFR) could be procured through the existing six second FCAS contingency service, this would not necessarily recognise any enhanced value that might be associated with the faster response. Consequently, FCAS markets should be reviewed in order to determine how FFR might best be incorporated into them.

Such a review will also offer the opportunity to consider wider questions as to whether existing FCAS markets will remain relevant in light of the changing generation environment and to reconsider the rationale for the specific services that currently exist. Going forward, FCAS may increasingly need to be co-optimised against dynamic system characteristics, such as the presence of inertia, and there may therefore be a need to integrate FCAS and other services, such as inertia provision.

Recommendation	How the recommendation will be implemented or further progressed
7. Assess whether existing frequency control arrangements will remain fit for purpose in light of likely increased ramping requirements, driven by increases in solar PV reducing operational demand at times and therefore leading to increased demand variation within a day.	Further consideration through the AEMC's *Frequency control frameworks review* (commencing **July 2017**) and AEMO's future work program.

Future work on frequency control arrangements will need to confront additional challenges. One such key issue is driven by the continued uptake in rooftop solar photovoltaics (PV). Greater levels of solar PV tend to decrease the power taken from grid over the middle of the day. Consequently, the slope of the demand curve in the ramp-up to the evening peak is getting steeper over time. As the scale of this challenge increases, the reducing levels of dispatchable thermal generation may mean that the capacity of the system to respond to it is reducing.

Recommendation	How the recommendation will be implemented or further progressed
8. Consider placing an obligation on all new entrant plant, whether synchronous or non-synchronous, to have fast active power control capabilities.	This recommendation will be considered for implementation through the AEMO rule change request to be submitted to the AEMC in **July 2017**, and is consistent with a recommendation made by AEMO in respect of South Australia.

Where they do not impose undue costs, technical obligations on plant to have the capability to provide certain services can act as a useful complement to service procurement mechanisms. However, defining specific requirements on new generation technologies to provide FFR are challenging as different technology types can offer very different services, for instance in response times or in the duration over which a response can be sustained. An obligation on new plant to have fast active power control capabilities, such that their active power output can be made automatically sensitive to system frequency or be directly controlled over very short timeframes, is consistent with FFR provision but avoids the need to prescribe specifically how responses must be delivered.

Facilitate the transformation

As the pace and scope of the transition expands, so will the future needs of the power system. There are a number of power system related issues that are likely to be necessary to further *facilitate the transformation*.

Recommendation	How the recommendation will be implemented or further progressed
9. Continue to scope further power system security issues likely to arise from the ongoing transformation of the market, such as: • the impact on system restart ancillary services of decreasing levels of synchronous generation; and • the adequacy of current voltage control arrangements.	AEMO to further scope these issues.

While this review has focussed on a small number of priority issues highlighted by AEMO, many other challenges have already been identified and others may yet emerge. These issues should continue to be monitored and scoped.

Frequency control frameworks review

To progress a number of recommendations made in this review, in July 2017 we will initiate a review into market frameworks necessary to support better frequency control: the *Frequency control frameworks review*. We intend to publish terms of reference for the review shortly, and to discuss its scope and structure with our existing technical working group and stakeholder reference group.

As with the *System security market frameworks review*, this further review will continue to be coordinated with the ongoing technical work being completed by AEMO on frequency control issues under the terms of our collaboration agreement reached on 8 July 2016.[1]

Independent Review into the Future Security of the National Electricity Market

At an extraordinary meeting on 7 October 2016, COAG Energy Ministers agreed to an independent review of the NEM to take stock of its current security and reliability, and to provide advice to governments on a coordinated, national reform blueprint.

The panel tasked with undertaking the *Independent Review into the Future Security of the National Electricity Market* was chaired by Dr Alan Finkel AO, and Dr Finkel presented the final report for the review to the COAG Leaders' meeting on 9 June 2017.

With regards to security, the Panel recommended the implementation of a set of "Energy Security Obligations" to ensure generators have appropriate technical capabilities, including in relation to changes in frequency and system strength.[2] The recommendations made by the Panel are, in large part, consistent with those made by the Commission, and we note that the implementation pathways we have identified will allow many of the Panel's recommendations to be progressed in a timely manner.

The table overleaf provides a comparison of the Panel's recommendations and views with the Commission's recommendations, and sets out how these recommendations can be progressed in timeframes consistent with those suggested by the Panel.

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1 The agreement is available at http://www.aemc.gov.au/getattachment/47f82c2a-92a1-4c3e-bb2c-5a02f431bced/AEMC-AEMO-scope-of-work.aspx

2 Commonwealth of Australia, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017, p. 49.

Summary comparison table of AEMC and Independent Review into the Future Security of the National Electricity Market recommendations

	AEMC recommendation	How our recommendation will be implemented or further progressed	Independent Review into the Future Security of the National Electricity Market recommendation
	A stronger system		
1	**Introduce regulatory arrangements to require network service providers to maintain the system strength at generator connection points above agreed minimum levels, with new connecting generators required to 'do no harm' to previously agreed levels of system strength.**	Draft arrangements published for consultation on **27 June 2017** as part of the draft determination made on the Managing power system fault levels rule change proposed by the South Australian government. Arrangements are scheduled to be finalised on **19 September 2017**.	No specific recommendation, but notes that the Panel agrees with the AEMC's approach (p. 58).
2	**Consider requiring inverters and related items of plant within a connecting party's generating system to be capable of operating correctly down to specified system strength levels.**	AEMO intends to submit a rule change to the AEMC by **July 2017** requesting revisions to the generator performance standards consistent with advice it has provided regarding South Australian generator licence conditions. This recommendation will be considered for implementation through the AEMO rule change request and is consistent with AEMO's advice provided in respect of South Australia.	2.1 As part of a package of Energy Security Obligations, by **mid-2018** the AEMC should review and update the connection standards in their entirety, which would include addressing system strength.
	Resisting frequency changes		
3	**Place an obligation on transmission network service providers to provide minimum required levels of inertia, or alternative equivalent services, to allow the power system to be maintained in a secure operating state.**	Draft obligations published for consultation on **27 June 2017** as part of the draft determination made on the Managing the rate of change of power system frequency rule change proposed by the South Australian government. Arrangements are scheduled to be finalised on **19 September 2017**.	2.1 As part of a package of Energy Security Obligations, by **mid-2018** the AEMC should require transmission network service providers to provide and maintain a sufficient level of inertia for each region or sub-region, including a portion that could be substituted by fast frequency response service.
4	**Introduce a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum obligation on transmission network service providers.**	Draft mechanism to be published for consultation on **7 November 2017** as part of the draft determination to be made on the Inertia ancillary service market rule change proposed by AGL.	No specific recommendation.

	AEMC recommendation	How our recommendation will be implemented or further progressed	Independent Review into the Future Security of the National Electricity Market recommendation
	Better frequency control		
5	**Assess whether mandatory governor response requirements should be introduced and investigate any consequential impacts (including on the methodology for determining causer pays factors for the recovery of regulation FCAS costs).**	In **July 2017** the AEMC will initiate a review into market frameworks necessary to support better frequency control: Frequency control frameworks review. AEMO has commissioned expert advice on the causes and impacts of deteriorating frequency control performance, for consideration by its Ancillary Services Technical Advisory Group in **July 2017**. The Commission will consider the outcome of this work and its implications through the review.	2.3 By **mid-2018**, AEMO and the AEMC should investigate and decide on a requirement for all synchronous generators to change their governor settings to provide a more continuous control of frequency with a deadband similar to comparable international jurisdictions.
6	**Review the structure of FCAS markets, to consider:** **• any drivers for changes to the current arrangements, how to most appropriately incorporate FFR services, or alternatively enhancing incentives for FFR services, within the current six second contingency service; and** **• any longer-term options to facilitate co-optimisation between FCAS and inertia provision.**	Further consideration through the AEMC's Frequency control frameworks review (commencing **July 2017**) and AEMO's future work program.	2.2 A future move towards a market-based mechanism for procuring fast frequency response (as proposed as in the System security market frameworks review) should only occur if there is a demonstrated benefit
7	**Assess whether existing frequency control arrangements will remain fit for purpose in light of likely increased ramping requirements, driven by increases in solar PV reducing operational demand at times and therefore leading to increased demand variation within a day.**	Further consideration through the AEMC's Frequency control frameworks review (commencing **July 2017**) and AEMO's future work program.	No specific recommendation, but notes that AEMO has recommended a requirement in South Australia for active power control facilities to be fitted to all variable renewable electricity generators. Among other things, this would require the control of ramp rates. It is suggested that AEMO should monitor the effectiveness of this new requirement and assess its application more broadly (p. 101).
8	**Consider placing an obligation on all new entrant plant, whether synchronous or non-synchronous, to have fast active power control capabilities.**	This recommendation will be considered for implementation through the AEMO rule change request to be submitted to the AEMC in **July 2017**, and is consistent with a recommendation made by AEMO in respect of South Australia.	2.1 As part of a package of Energy Security Obligations, by **mid-2018** the AEMC should require new generators to have fast frequency response capability.
	Facilitating the transformation		
9	**Continue to scope further power system security issues likely to arise from the ongoing transformation of the market, such as:** **• the impact on system restart ancillary services of decreasing levels of synchronous generation; and** **• the adequacy of current voltage control arrangements.**	AEMO to further scope these issues.	No specific recommendation, but notes that it is important to maintain sufficient black start services as the generation mix changes (p. 61).

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1 Introduction

The *System security market frameworks review* was initiated by the Australian Energy Market Commission (AEMC or Commission) in July 2016 to consider changes to the regulatory arrangements to support the current shift towards new forms of generation in the National Electricity Market (NEM).[3] The focus of the review has been on addressing priority issues to allow the Australian Energy Market Operator (AEMO) to continue to maintain power system security as the market transitions.

Under the National Electricity Law (NEL), AEMO's statutory functions include maintaining and improving power system security (s.49(1)(e)). Consequently, the review has adopted the priorities identified by AEMO in its *Future Power System Security* (FPSS) program, which it initiated in December 2015. The work of the AEMC through this review has been to identify and develop the changes to market and regulatory arrangements required to address the technical issues highlighted by AEMO.

This final report sets out the Commission's conclusions and findings for the review. It makes a number of recommendations, both for immediate measures to address the priority issues and a further program of work to develop robust market frameworks for the longer term. In addition, it provides an indication of the next issues that will need to be considered to support the ongoing transformation of the market.

The Commission has been assessing five rule changes relating to a number of the priority issues concurrently and in coordination with the review. This report therefore also explains how these rule changes have been and are being used to implement the package of immediate actions.

1.1 Priority power system security issues

The electricity sector in Australia is experiencing a period of change as the proportion of newer types of electricity generation, such as wind and solar, increases. Traditional forms of large-scale, synchronous, centrally-dispatched generation are retiring, and being replaced by intermittent, non-synchronous, often distributed generation.[4]

This shift presents challenges for the NEM market and regulatory arrangements, as synchronous generation has a number of physical attributes that have, to date, not been separately valued in the market. One such property is the physical inertia provided by the large rotating mass of the turbine and alternator. These rotate synchronously with system frequency, and their mass resists changes to frequency almost instantaneously.[5]

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3 The review was initiated by the AEMC under section 45 of the NEL on 14 July 2016. Regulatory frameworks in this context refer to the National Electricity Rules (NER) and the NEL.

4 While some new synchronous generation appears likely to enter the market, in some cases as a result of government ownership or targets, the broader transition has highlighted issues that will still need to be addressed.

5 AEMO, *Future Power System Security Program*, Progress Report, August 2016, p. 10.

Non-synchronous generators, often being connected to the power system through inverters, are not electro-mechanically coupled to the frequency of the power system and therefore do not provide this damping effect, even where the power generation is the result of mechanical movement (e.g. wind). Consequently, additional approaches to maintaining power system security are now required.

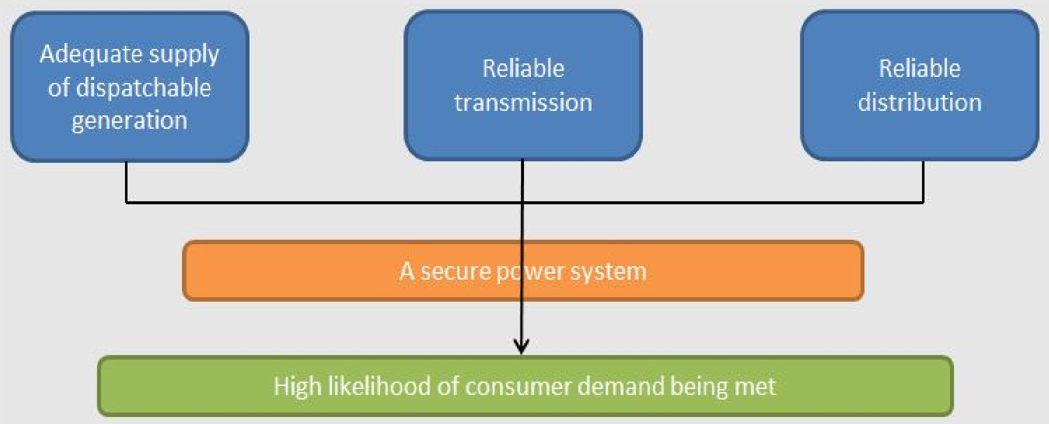
Power system security is defined in the National Electricity Rules (NER or rules) as the safe scheduling, operation and control of the power system in accordance with the power system security principles. These principles include maintaining the power system in a secure operating state and returning the power system to a secure operating state following a contingency event or a significant change in power system conditions, including a major supply disruption. Power system security is interrelated with technical parameters such as power flows, voltage, frequency, the rate at which these might change and the ability of the system to withstand faults.

Box 1.1 System security is distinct from reliability

System security is distinct from reliability. Reliability of supply has a consumer focus and describes the likelihood of supplying all consumer needs with the available generation capacity and network capability. As shown in Figure 1.1, the components of reliability include an adequate supply of dispatchable generation to meet demand and reliable transmission and distribution networks.

A secure operating system is a necessary condition for meeting consumer electricity needs. Security of supply is a measure of the power system's capacity to continue operating within defined technical limits, even in the event of the disconnection of a major power system element such as an interconnector, large generator or large load.

Figure 1.1 Components of system security and reliability



In contrast, reliability is driven the availability of generation and network capacity. Over the longer term, investment in new generation capacity is influenced by a broad range of factors, including expectations of wholesale market outcomes, and network investment by planning standards and regulatory investment tests.

1.2 AEMO's Future Power System Security Program

In response to the power system security challenges emerging in the market, AEMO established its FPSS program in December 2015. It also convened a Power System Issues Technology Advisory Group (PSI TAG) of technical experts to assist in the qualitative identification and prioritisation of the technical challenges.

Following its consultation with PSI TAG, AEMO identified four issues for immediate progression:[6]

- **Frequency control** - Managing frequency involves balancing the supply of electricity against demand on an instantaneous basis. Large deviations from the normal frequency level or high rates 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 synchronous plant (generators, motors and other devices). However, many new generation technologies are non-synchronous, have low or no physical inertia, and are, therefore, currently limited in their ability to dampen rapid changes in frequency.

- **Management of extreme power system conditions** - High levels of RoCoF can cause a particular issue in terms of rendering emergency frequency control schemes, that otherwise form the "last line of defence" against unforeseen power system issues, ineffective. AEMO identified a need to put in place arrangements that would support the introduction of new schemes that would better address under-frequency situations (where demand suddenly exceeds generation) and to establish schemes to address over-frequency instances (where generation exceeds demand).

- **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. Maintaining voltage stability and ensuring network protection equipment continues to function effectively present further challenges.

- **Visibility of the power system (information, data and models)** - The ability to model the power system effectively requires information and understanding of the electrical characteristics of all components of the power system that can have a material impact on its dynamic behaviour. AEMO is concerned that this is

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6 AEMO, *Future Power System Security Program*, Progress Report, August 2016, p. 4.

becoming increasingly complex as the market shifts towards increasing amounts of non-synchronous and, particularly, distributed energy resources, such as rooftop solar photovoltaics (PV).

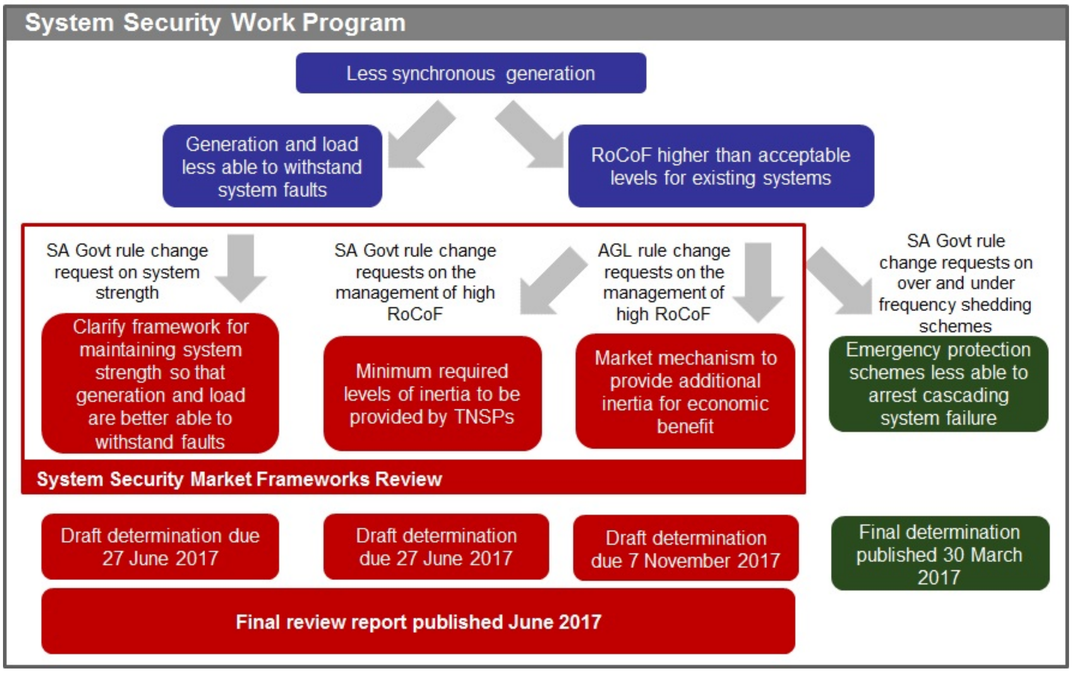
The impacts on the regulatory frameworks of the last of these issues - visibility of the power system - are being addressed through a number of other processes, including a rule change request submitted by AEMO[7] and the AEMC's "Distribution Market Model" project.[8] The first three issues have been considered by the AEMC through the System Security Work Program, as explained in the following section.

1.3 System security work program

The AEMC's System Security Work Program has been comprised of the *System security market frameworks review* and five related rule change requests received on system security matters. Four of the rule changes were submitted by the South Australian government, with the fifth requested by AGL. These rule changes have been progressed concurrently and in coordination with the review.

Figure 1.1 shows the relationship between the issues 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 1.2 AEMC System Security Work Program



The South Australian government's rule change requests regarding over and under-frequency shedding schemes were progressed separately to the review and the other three rule change requests. These rule change requests sought to refine the

7 See: AEMO, *Generating System Model Guidelines*, Rule Change Request, 28 October 2016.

8 See: AEMC, *Distribution Market Model*, Approach Paper, 1 December 2016.

existing arrangements for emergency under-frequency control schemes and to establish a regulatory framework for over-frequency control schemes, respectively. As the two rule change requests related to similar matters, the Commission decided to consolidate them into a single rule change under s.93(1) of the National Electricity Law.

On 30 March 2017, the Commission issued a final determination for the combined rule change.[9] The Commission determined to introduce new arrangements that include:

- a framework to regularly review current and emerging power system frequency risks, and then identify and implement the most efficient means of managing emergency frequency events
- an enhanced process to develop emergency frequency control schemes to allow for the efficient use of all available technological solutions to limit the consequences of emergency frequency events, including a formalised arrangement for the management of over-frequency events
- a new classification of contingency event, the protected event, that in the circumstances defined by such an event, will allow power system security to be managed by using a combination of ex-ante solutions, as well as some limited generation or load shedding.

These new arrangements commenced on 6 April 2017.

The remaining three rule change requests cover a range of complex issues for which technical solutions are only now beginning to be 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.

The Commission is making draft determinations for two of these rule changes concurrently with the publication of this final report. Chapter 3 of the report explains the issues that the Commission considers can be addressed immediately through these rule changes, as well as its approach to the last of the rule changes.

1.4 Assessment framework

In undertaking the *System security market frameworks review*, as in all its work, the Commission has been guided by the National Electricity Objective (NEO). The NEO is set out in section 7 of the NEL, as follows:

> "The objective of this law is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:
>
> - price, quality, safety, reliability and security of supply of electricity; and

9 AEMC, *Emergency frequency control schemes*, Rule determination, 30 March 2017.

- the reliability, safety and security of the national electricity system."

Based on its assessment of the issues raised by the Review and the related rule change requests, the Commission considers that the relevant aspects of the NEO are the efficient investment in and operation of electricity services with respect to the safety and security of the national electricity system and the price of supply of electricity.

To develop recommendations for changes to the market and regulatory frameworks, and test the proposed rules, the Commission considered the following propositions in relation to the promotion of the NEO:

- The safety and security of the national electricity system provides operational and investment certainty to market participants. This leads to efficient price signals and minimises the costs of investment in the long-term interests of consumers of electricity.
- The competitive procurement of services minimises the costs of maintaining the security of the national electricity system, thereby lowering the price of electricity to consumers.
- Where changes to regulatory arrangements are required they should be designed, to the extent feasible, to coordinate options for the maintenance of system security such that total system cost is minimised.

1.4.1 Principles

At the commencement of the review, the Commission identified a number of principles to guide the development of recommendations on potential changes to market and regulatory frameworks that affect system security in the NEM. These principles were also used to guide the Commission's assessment of the rule change requests in addition to the NEO.

1. **Technology neutrality:** Regulatory arrangements should be designed to take into account the full range of potential market and network solutions. They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind. Technologies are changing rapidly and, to the extent possible, a change in technology should not require a change in regulatory arrangements.
2. **Market mechanisms:** 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. Such outcomes should be less likely to change over time, creating regulatory certainty. Any market-based solution should be designed to maximise opportunities for the provision of services in order to send the right price signals and lower the overall cost of achieving a secure electricity system.

3. **Flexibility:** Regulatory arrangements must be flexible to changing market conditions. They must be able to remain effective in achieving system security over the long term in a changing market environment.

   Further, regulatory or policy changes should not be implemented in a way that will only address issues that arise at a specific point in time or in a specific jurisdiction. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions and apply across the whole of the NEM. They should be effective in maintaining system security where it is needed while not imposing undue market or compliance costs on other areas.

4. **Risk allocation:** Regulatory arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of meeting system security requirements. Risk allocation and the accountability for investment decisions should rest with those parties best placed to manage them. Under a centralised planning arrangement, risks are more likely to be borne by customers. Solutions that are better able to allocate risks to market participants such as businesses who are better able to manage them are preferred where practicable.

1.5 Structure of this report

The remainder of this final report is structured as follows:

- Chapter 2 discusses the two priority power system security issues considered through the review: frequency control and system strength;
- Chapter 3 presents an overview of the Commission's recommendations, and explains how these recommendations will be implemented or further progressed, including through rule changes for which draft determinations have been published concurrently with this report; and
- Chapters 4-6 set out in greater detail the Commission's recommendations that are not the subject of the current draft determinations, as follows:
  - Chapter 4 explains the Commission's updated approach to the provision of inertia to realise market benefits;
  - Chapter 5 provides more background to the Commission's proposed program of work for the further development of frequency control frameworks; and
  - Chapter 6 discusses the recommendations the Commission is making in regards to technical standards, and how these will be progressed.

2 Priority power system security issues

This chapter sets out the two priority power system security issues considered through the review, frequency control and system strength, and how these inform the Commission's recommendations.

Fuller discussions of these issues are contained in the interim report (for frequency control)[10] and the discussion paper (for system strength).[11]

2.1 Power system frequency issues

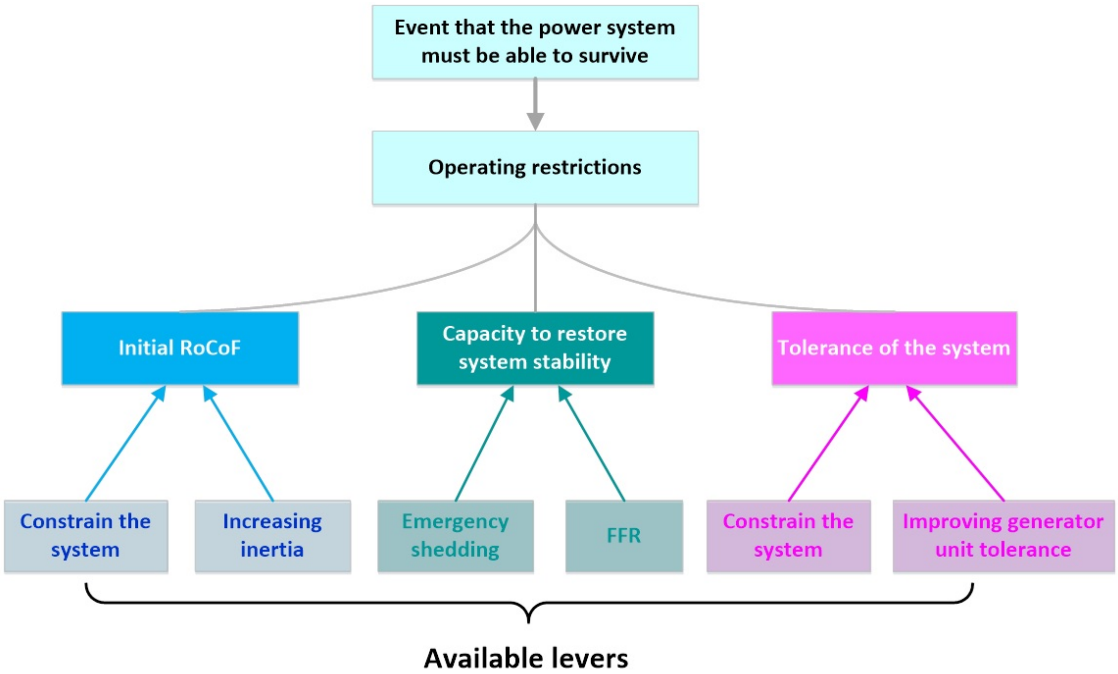
The interim report identified the factors that influence the ability to maintain control of power system frequency following a contingency event, such as the loss of a large generator, load or transmission line. These can be considered through the following three-part framework:

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.

Figure 2.1 Factors that influence the control of power system frequency



10 AEMC, *System security market frameworks review*, Interim Report, 15 December 2016, Chapter 3.

11 AEMC, *System security market frameworks review*, Directions Paper, 23 March 2017, Chapter 5.

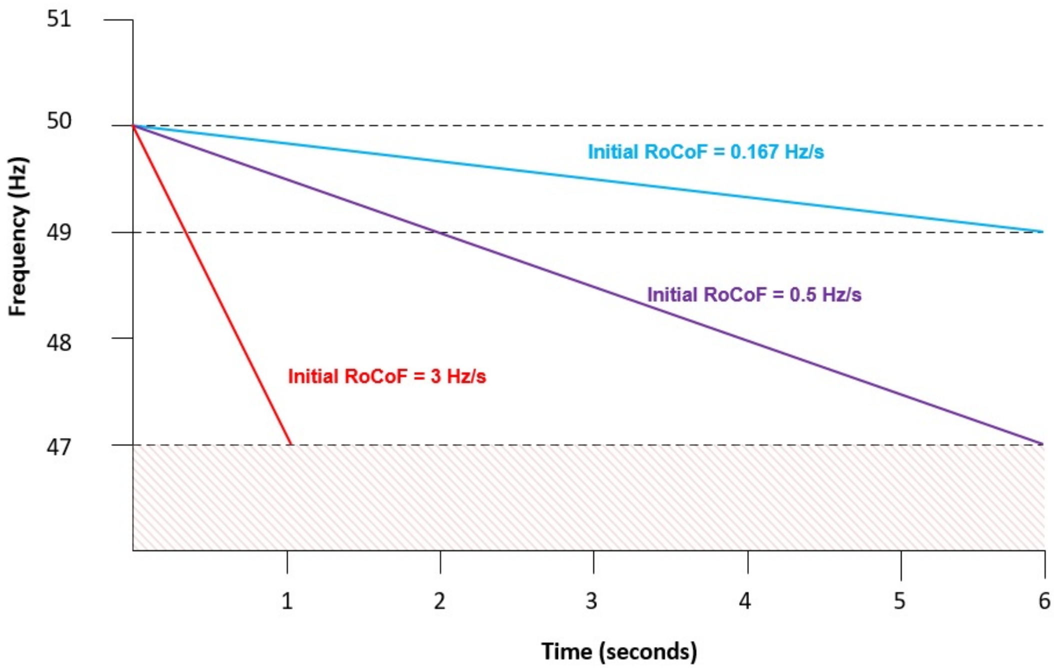
2.1.1 Initial rate of change of frequency

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.

Figure 2.2 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[12] – 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 2.2 Initial RoCoF determines the time available to respond

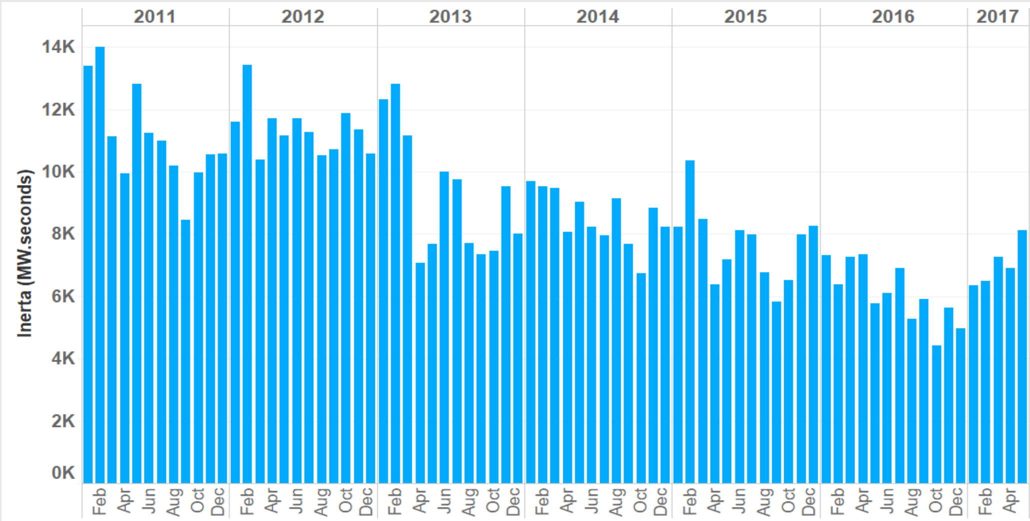


12 It should be noted that, in practice, the response takes effect over the six second period rather than precisely at the six second mark. It should also be noted that the system frequency at the time of the contingency may not be exactly 50 Hz. Under normal operating conditions, the system frequency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

Box 2.1 Current frequency issues in South Australia

The immediate challenges of restricting high rates of change of frequency are most acute in South Australia. South Australia has experienced a high level of investment in non-synchronous generation relative to its total generation capacity. In addition, a number of conventional synchronous generators have recently retired. Figure 2.3 shows how levels of system inertia in South Australia have decreased over time.

Figure 2.3 System inertia in South Australia over time



Source: Endgame Economics.

AEMO has noted that this decline in system inertia does not affect the stable operation of the power system in South Australia as long as the Heywood Interconnector to Victoria remains in service. This is because system inertia is provided to South Australia via the AC link.

However, an unexpected failure of the Heywood Interconnector could threaten system security in South Australia. If flows on the interconnector were relatively high and there was relatively little inertia present in South Australia, very high rates of change of frequency could result. These could exceed the maximum level at which the existing under-frequency load shedding scheme would be effective in restoring the supply-demand balance.

On 4 October 2016, AEMO introduced constraints to limit the rate of change of frequency to below 3 Hz per second for the non-credible coincident trip of both circuits of the Heywood Interconnector, following a direction issued by the South Australian Minister. AEMO had previously suggested it would be unlikely that the requirements of the Frequency Operating Standards would be met should South Australia separate from the rest of the NEM following a non-credible contingency if RoCoF was above this level.[13]

13 AEMO, *Future Power System Security Program*, Progress Report, August 2016, Figure 5.

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.

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 on an interconnector may limit the ability of power to flow from a lower priced region to a higher priced 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.

To date, there has been no ability for AEMO or any other party to obtain additional inertia. In the past, inertia has been plentiful and so such a mechanism has not previously been required. Over the course of the review, the Commission concluded that the ability to maintain system security in an efficient manner would be enhanced by the development and introduction of mechanisms to obtain and pay for inertia.

Such services 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.[14] Consequently, an inertia service would have to initially be provided by synchronous machines, at least in part.

However, in the future, it may become possible to use inverter-connected devices (such as energy storage devices) to constantly and “instantaneously” maintain frequency.[15] Consequently, inertia services should be defined in such way as to accommodate new technology options.

2.1.2 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.

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

15 Ibid.

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.

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 2.2, 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 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 undertaking work to consider in detail how a technical specification for a FFR service might be developed.[16] 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.[17]

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 have not yet been deployed on a widespread basis, with no international markets having significant experience operating a FFR-type service. Some of the limited examples include a two-second FFR service recently

16 AEMO, *Fast Frequency Response Specification*, Release of GE Energy Consulting Report, 15 March 2017, p. 2.

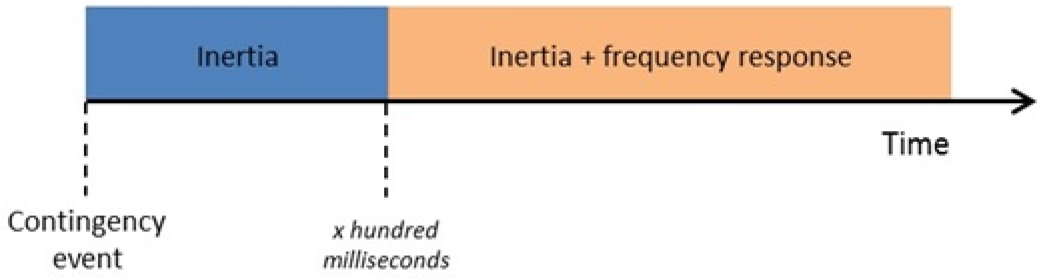
17 This assumes that the system frequency is at precisely 50 Hz at the time of the contingency event.

implemented in Ireland (October 2016) and a one-second demand response service used in New Zealand.[18] However, over the course of the review a number of stakeholders suggested that faster responding services than this may be possible.[19]

Nevertheless, the Commission notes that, 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 additional inertia to stabilise system frequency. This distinction between the roles of the two services is illustrated in Figure 2.4 below.

Figure 2.4 Timeline for inertia and fast frequency response



2.1.3 Tolerance of the system

The amounts of inertia and FFR services to be procured will depend of the levels of the RoCoF constraints applied to dispatch by AEMO. In order to derive appropriate RoCoF limits, it will be important to understand the tolerance of all parts of the system to those levels 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.

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

19 Reach, submission to the interim report, p. 7; RES, submission to the interim report, p. 3.

The performance standards relating to the ability of generators to withstand rates of change of system frequency are set out in the NER. 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.[20] 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 levels is largely dependent on the operating and market conditions that were present at the time of the event.

Consequently, gaining the best possible understanding of the technical characteristics of all connected plant will be an important complement to developing procurement mechanisms for inertia and FFR to address RoCoF issues.

2.2 System strength issues

The second priority issue considered through the review has been system strength. System strength is an inherent characteristic of an alternating current power system, and refers to the relative change in voltage for a change in load or generation at a connection point. When system strength is high, the voltage will change less for a change in load (or generation) than it would if the system strength was low.

2.2.1 Background

How is system strength expressed?

System strength is often referred to as the fault level. This is because the current that flows into a fault is larger in a system with higher system strength. The system strength can be expressed as the magnitude of the current that would flow into the fault and is thus measure in Amperes (A). However, more commonly, the system strength at a connection point is measured as the product of the fault current and the nominal voltage. This is measured in megavolt amps (MVA).

The system strength for a particular generating unit or inverter system can be referred to as the short circuit ratio (SCR), which is that ratio of the system strength in MVA, and the capacity (in MW) of the generating unit or inverter.[21]

20 Clause S5.2.5.3 of the NER.

21 A 200 MW generating unit at a connection point with a system strength of 1000 MVA would have a SCR of 5, that is 1000/200.

Box 2.2 What affects system strength?

The system strength at any point in the power system depends on the surrounding network. The system strength will be higher when:

- there is a greater number of synchronous generating units nearby
- the point in the network is connected to those 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.[22] It is possible that future inverter-based generation will be able to make a greater contribution to the system strength.

Faults in power systems and their management

In a power system, a fault is an abnormal condition. The most common type of fault is a short-circuit fault. This is when a conductor makes contact with the ground or another line. A short circuit fault can result from conditions such as lightning or bush fires. Faults can also occur within items of electrical plant such as transformers or capacitor banks when the plant is damaged.

When a fault occurs, the voltage around the fault will fall and the current flowing into the fault will increase.

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. Clearing faults in a timely manner is essential so that:

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

There are protection systems in the transmission network that locate and clear faults. When protection systems detect a fault, usually due to a sudden increase in current flow, the system will open circuit breakers to isolate the fault.

The speed at which the faults are cleared is critical to both maintain safety and limit the risk of damage, as well as the continuation of the operation of the power system. The maximum allowable fault clearance times for different voltage levels are defined in the NER.[23] The NER specifies faster clearance times for high voltages as the consequences of prolonged faults are greater.

22 S&C Electric, submission to the directions paper, p. 3.

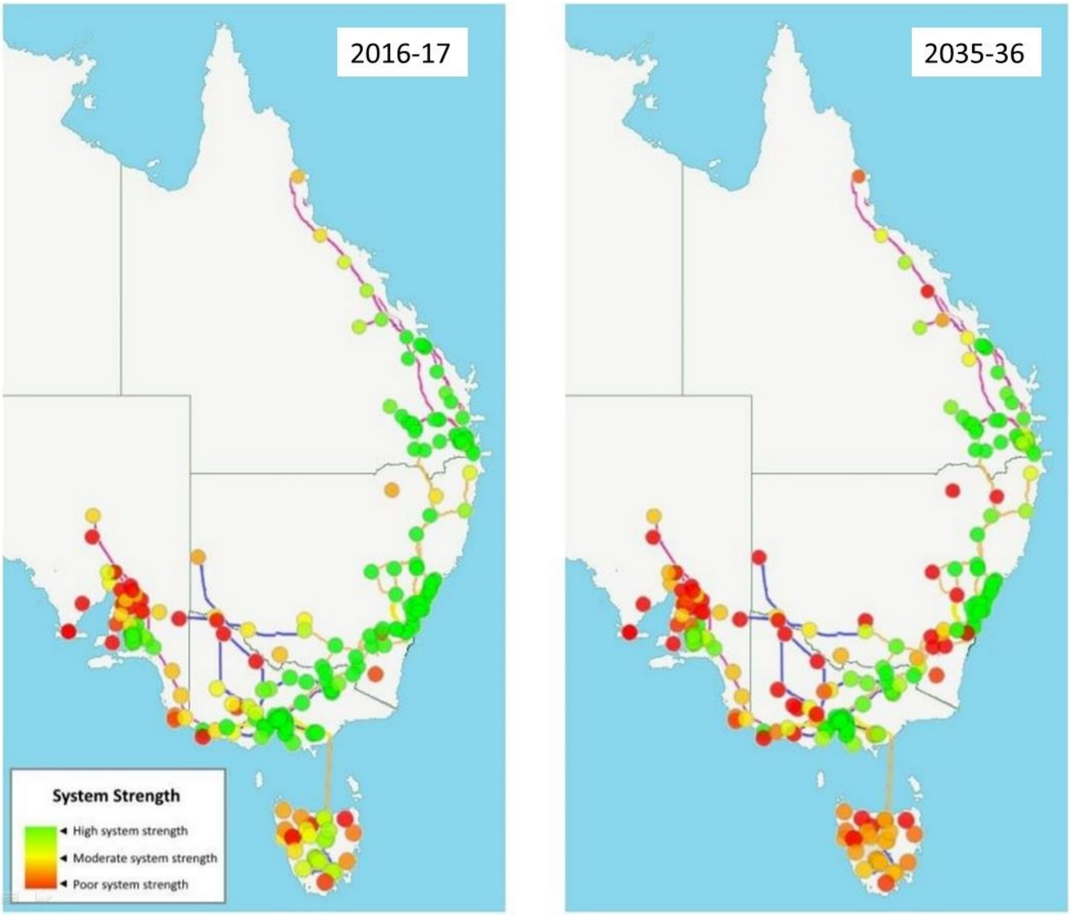
23 Table S5.1a.8 of the NER.

Emerging system strength issues

Historically, the primary concern has been that system strength may be too high and fault currents may damage equipment. High faults levels become an issue if the fault level at a location exceeds the rating of the affected electrical equipment. Of particular concern 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.[24]

However, falling system strength is now an emerging issue. System strength in some parts of the power system has been decreasing as traditional synchronous generators are operating less or being decommissioned. The SCR at connection points are also falling as greater numbers of non-synchronous generators connect to the network.

Figure 2.5 System strength in 2016–17 and 2035–36



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

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

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

in the NEM, while there will be over 22 GW of large-scale inverter-connected generation connected (not including rooftop PV).[25] This displacement of synchronous generation is projected to greatly reduce system strength across the NEM, as shown in Figure 2.5 above.

The figure shows a high-level assessment of where system strength is an existing or emerging challenge. An area of the grid is generally considered weak if the SCR drops below three.[26] For this assessment, AEMO weighted the SCR[27] to determine network strength.

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[28]
- 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 following sections discuss each of these three issues in turn.

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

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

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

26 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.

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

28 Australian Standards AS/NZS 61000.3.7:2012.

- 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.

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 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. It may therefore be necessary to restore the system strength within the affected portion of the power system using synchronous condensers or contracting existing synchronous generators.

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.

Allocation of roles and responsibilities

Currently, NSPs are responsible for the provision and operation of the protection systems for their networks.[29] 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 has therefore concluded that it is not necessary to make any 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 Transmission Network Service Providers (TNSPs) and the Distribution Network Service Providers (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. Consequently, joint planning processes between TNSPs and DNSPs should consider the most efficient options to address the system strength issues in both networks.

2.2.3 Ability to manage network voltages with reduced system strength

Nature of the issue

Network Service Providers (NSPs) are required to keep the voltage at network users' (including customers' and generators') connection points within technical limits, including:[30]

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

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

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

- 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 reactor bank. Of particular concern is that automatic voltage control systems can become unstable at low fault levels.

Technical solutions

There are a number of potential technical solutions for voltage control issues, with the most appropriate solution dependent of the severity of the problem.

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 reactor banks would include multiple capacitor banks to inject reactive power and may include reactor banks to absorb reactive power.

However, 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.[31]

Dynamic voltage control devices

Static VAr compensators (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.

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31 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.

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. However, the disadvantage of SVCs and STATCOMs is that they cost significantly more than a similarly sized switched capacitor and reactor banks scheme.

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

Allocation of roles and responsibilities

Currently, NSPs are responsible for the management of the voltage within their network.[33] 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.

The Commission has therefore concluded that it is not necessary 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.[34] 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:

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

33 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.

34 The obligation on NSPs to work together when considering the system strength within their networks is consistent with their obligations in Rule 5.14 to undertake joint planning when assessing the adequacy of the networks.

- 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[35] 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.[36]

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

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.[37] 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 power system. This information will include the type of generation, the associated control and protection systems, as well as detailed modelling data to be used in power system studies.[38]

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35 Models are mathematical representations of how particular equipment, such as a generating unit or network equipment, will function under different conditions. They are used as inputs to broader modelling studies of the power system, referred to as power system studies.

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

37 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.

38 On 20 June 2017 the Commission published a draft determination and draft rule on the *Generating system model guidelines* rule change request, which clarifies the obligations on market participants to provide modelling data information to AEMO. See: AEMC, *Generating system model guidelines*, Draft rule determination, 20 June 2017.

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

Reducing system strength means that generating units in the NEM may no longer be capable of meeting their performance standards at periods of low system strength, which could have severe consequences such as cascading outages leading to a major supply disruption or potentially even 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, i.e. 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.

Technical solutions

The potential solutions when a generator is unable to meet its technical performance standards 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
- 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.

Allocation of roles and responsibilities

The Commission understands that some connection agreements[39] 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
- new non-synchronous generating units enter the market, reducing the short circuit ratio of proximate pre-existing generating units
- 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.

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.

Consequently, a key focus of the review has been to consider how best to allocate this role and to develop the detailed arrangements to support this. The following chapter sets out the Commission's recommendations in this regard, and explains how they will be implemented.

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

3 Recommendations

This chapter sets out the Commission's recommendations, both for immediate measures to address the priority issues and a further program of work to develop robust market frameworks for the longer term. It also provides an indication of the next issues that will need to be considered to support the ongoing transformation of the market.

Table 3.1 Summary of recommendations

Recommendation	How the recommendation will be implemented or further progressed
A stronger system	
1. Introduce regulatory arrangements to require network service providers to maintain the system strength at generator connection points above agreed minimum levels, with new connecting generators required to ‘do no harm’ to previously agreed levels of system strength	Draft arrangements published for consultation on **27 June 2017** as part of the draft determination made on the *Managing power system fault levels* rule change proposed by the South Australian government. Arrangements are scheduled to be finalised on **19 September 2017**.
2. Consider requiring inverters and related items of plant within a connecting party's generating system to be capable of operating correctly down to specified system strength levels.	AEMO intends to submit a rule change to the AEMC by **July 2017** requesting revisions to the generator performance standards consistent with advice it has provided regarding South Australian generator licence conditions. This recommendation will be considered for implementation through the AEMO rule change request and is consistent with AEMO’s advice provided in respect of South Australia.
Resisting frequency changes	
3. Place an obligation on transmission network service providers to provide minimum required levels of inertia, or alternative equivalent services, to allow the power system to be maintained in a secure operating state.	Draft obligations published for consultation on **27 June 2017** as part of the draft determination made on the *Managing the rate of change of power system frequency* rule change proposed by the South Australian government. Arrangements are scheduled to be finalised on **19 September 2017**.
4. Introduce a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum obligation on transmission network service providers.	Draft mechanism to be published for consultation on **7 November 2017** as part of the draft determination to be made on the *Inertia ancillary service market* rule change proposed by AGL.

Recommendation	How the recommendation will be implemented or further progressed
Better frequency control	
5. Assess whether mandatory governor response requirements should be introduced and investigate any consequential impacts (including on the methodology for determining causer pays factors for the recovery of regulation FCAS costs).	In **July 2017** the AEMC will initiate a review into market frameworks necessary to support better frequency control: *Frequency control frameworks review*. AEMO has commissioned expert advice on the causes and impacts of deteriorating frequency control performance, for consideration by its Ancillary Services Technical Advisory Group in **July 2017**. The Commission will consider the outcome of this work and its implications through the review.
6. Review the structure of FCAS markets, to consider: • any drivers for changes to the current arrangements, how to most appropriately incorporate FFR services, or alternatively enhancing incentives for FFR services, within the current six second contingency service; and • any longer-term options to facilitate co-optimisation between FCAS and inertia provision.	Further consideration through the AEMC's *Frequency control frameworks review* (commencing **July 2017**) and AEMO's future work program.
7. Assess whether existing frequency control arrangements will remain fit for purpose in light of likely increased ramping requirements, driven by increases in solar PV reducing operational demand at times and therefore leading to increased demand variation within a day.	Further consideration through the AEMC's *Frequency control frameworks review* (commencing **July 2017**) and AEMO's future work program.
8. Consider placing an obligation on all new entrant plant, whether synchronous or non-synchronous, to have fast active power control capabilities.	This recommendation will be considered for implementation through the AEMO rule change request to be submitted to the AEMC in **July 2017**, and is consistent with a recommendation made by AEMO in respect of South Australia.
Facilitating the transformation	
9. Continue to scope further power system security issues likely to arise from the ongoing transformation of the market, such as: • the impact on system restart ancillary services of decreasing levels of synchronous generation; and • the adequacy of current voltage control arrangements.	AEMO to further scope these issues.

3.1 A stronger system

As discussed in the previous chapter, in respect of system strength issues the Commission has concluded that:

- the existing provisions in the NER adequately allocate responsibility for network protection and voltage issues to NSPs, but that
- there is a need to allocate responsibility to maintain the short circuit ratio at generation connection points.

Through the review, the Commission therefore considered which party would be best placed to manage system strength such that generators were able to continue to meet their performance standards.

3.1.1 Issues associated with requiring 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[40] 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.

3.1.2 Potential for NSPs to maintain 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

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

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 recommendation, TNSPs would be required to provide a defined operating level of inertia (see next section). 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.

> ***Recommendation 1:*** *Introduce regulatory arrangements to require network service providers to maintain the system strength at generator connection points above agreed minimum levels, with new connecting generators required to 'do no harm' to previously agreed levels of system strength.*

3.1.3 Draft determination to allocate responsibility for power system fault levels

The Commission is implementing the above recommendation through the *Managing power system fault levels* rule change proposed by the South Australian government. A draft rule and draft determination for the rule change have been published concurrently with this report.[41]

Further details can be found in the draft determination document but, in summary, the key features of the draft rule are:

- An enhanced framework that requires network service providers to maintain the system strength at generator connection points above an agreed minimum level, under a defined range of conditions. This builds on the existing arrangements for generators to meet their registered performance standards. The enhanced framework is technology neutral and requires the network service provider to use existing planning and regulatory arrangements when acquiring or providing

41 AEMC, *Managing power system fault levels*, Draft rule determination, 27 June 2017.

services to assist in the maintenance of system strength above the registered levels.

- The introduction of a requirement on new connecting generators to 'do no harm' to the minimum level of system strength previously negotiated by existing generators at their connection points. When negotiating its connection with the NSP, the new generator would have to agree to provide or fund the provision of any required system strength services to maintain system strength such that it could meet its performance standards and satisfy the NSP and AEMO that all short circuit ratios agreed by the NSP with existing generators could be maintained.

- A transitional process for existing generators to agree a registered short circuit ratio at their connection point with the relevant NSP. Generators and NSPs would be required to negotiate and agree to a minimum short circuit ratio which would then be registered with AEMO. This short circuit ratio would then be maintained as on ongoing obligation by the NSP.

- The introduction of a requirement on AEMO to identify locations in the network where system strength is below, or is likely to be below, the registered minimum level of system strength. This is a clarification of AEMO's current role in maintaining system security, including taking actions where necessary to maintain system security when system strength is low. This is also consistent with the existing NER treatment of high fault levels, which AEMO has a role in monitoring and managing. In addition, AEMO would be responsible for establishing a guideline for calculating the short circuit ratio at connection points.

The Commission is currently inviting submissions on the draft rule determination, with these being due by 8 August 2017. The final determination is currently scheduled to be made on 19 September 2017.

Under the draft rule, there would be a transitional period for NSPs to agree minimum short circuit ratios with existing generators beginning shortly after publication of the final determination. The full arrangements, including the new connection process provisions, would commence on 1 July 2018.

3.1.4 Minimum technical requirements for inverter-based generation

In many parts of the NEM, the system strength is still relatively high and is likely to remain that way for several years, because there are currently baseload synchronous generating units operating there. The installation of a new inverter-based generating system in one of these locations would not introduce a system strength issue, as the short circuit ratio would be relatively high.

In such circumstances, there may be little incentive on either the generator or the NSP to seek to minimise the effect of the connection on the local short circuit ratio. While this would not cause an immediate problem, it may increase costs for subsequent connections and/or consumers, as a potentially unnecessarily high short circuit ratio would have to be maintained over time. Consequently, the Commission considers that there would be merit in requiring inverters and related items of plant to be capable of operating at low minimum short circuit ratios, as this could significantly reduce future mitigation costs.

This recommendation is consistent with advice on recommended technical standards for generator licensing in South Australia recently provided by AEMO to the Essential Services Commission of South Australia (ESCOSA). In its advice, AEMO further noted that it intends to submit a rule change to the AEMC by July 2017 proposing revisions to the generator performance standards in the NER. One aim of the rule change would be for any new licence conditions imposed by ESCOSA to be transitional arrangements that are eventually able to be repealed, in whole or in part, following appropriate updates to the technical standards in the NER.[42]

The Commission consequently intends to use the process of assessing the rule change request to be made by AEMO to further examine, and potentially implement, the recommendation that new inverter-based generation should be required to operate at a minimum short circuit ratio, and to consider what the level should be and how it should be measured. More detail on this recommendation is contained in chapter 6 of this report.

> ***Recommendation 2:*** *Consider requiring inverters and related items of plant within a connecting party's generating system to be capable of operating correctly down to specified system strength levels.*

3.2 Resisting frequency changes

As discussed in the previous chapter, in respect of frequency issues the Commission has concluded that:

- the ability to maintain power system security in an efficient manner would be enhanced by the development and introduction of mechanisms to obtain and pay for inertia
- the development of 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, noting that current FFR technologies cannot act as a complete substitute for inertia
- understanding the technical characteristics of all connected plant will be an important consideration when designing services to manage RoCoF issues.

Through the review, the Commission therefore considered how services should best be designed to address issues associated with potentially greater RoCoF, and which party or parties should be responsible for procuring these services.

42 AEMO, *Recommended technical standards for generator licensing in South Australia*, 31 March 2017, p. 16.

3.2.1 Determining the level of services required

The drivers for limiting the immediate RoCoF can be considered as two components:

- minimum requirements to maintain system security
- potential market benefits with levels above this minimum.

Minimum requirements to maintain system security

Under the NER, AEMO must operate the power system such that, to the extent practicable, it is and will remain in a secure operating state.[43] In terms of frequency control, this means that system frequency must stay within the bounds specified in the FOS following the occurrence of a credible contingency[44] or protected event.[45]

Prior to the occurrence of such 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.

However, short of constraining all generation and network flows - and therefore demand - to zero, there is a minimum level of inertia required even to operate the system in a heavily constrained manner. Such a level would provide:

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

Market benefits associated with additional inertia

Additional inertia above the minimum level associated with maintaining system security would allow the system to be operated in a more unconstrained manner. Constraints to limit the maximum contingency size would have economic costs in that the output of some generating units and/or the flows on some elements of the transmission network (such as interconnectors) would have to be reduced. Such constraints would be likely to increase wholesale electricity prices. For example, a

43 Clause 4.2.6(a) of the NER.

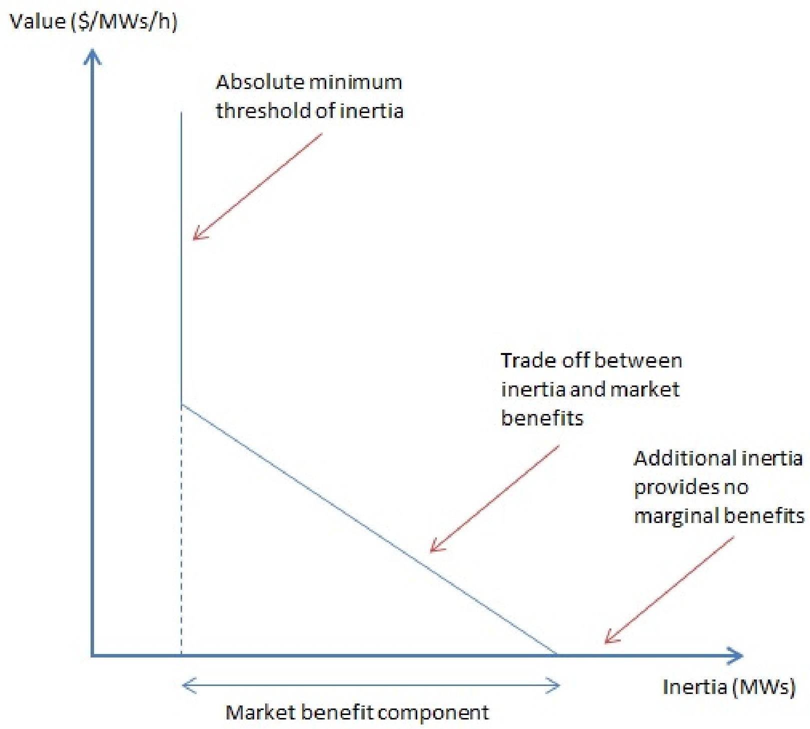
44 A credible contingency is an event which AEMO considers to be reasonably possible. Generally, such events would involve the loss of one generating unit or network element.

45 A protected event is a non-credible contingency that, following a declaration by the Reliability Panel, must be managed in a similar manner to credible contingencies.

constraint on an interconnector may limit the ability of power to flow from a lower priced to a higher priced region.

The split between these two types of benefit is illustrated in figure 3.1, which shows a theoretical demand curve for inertia.

Figure 3.1 Value of inertia and the amount of inertia provided

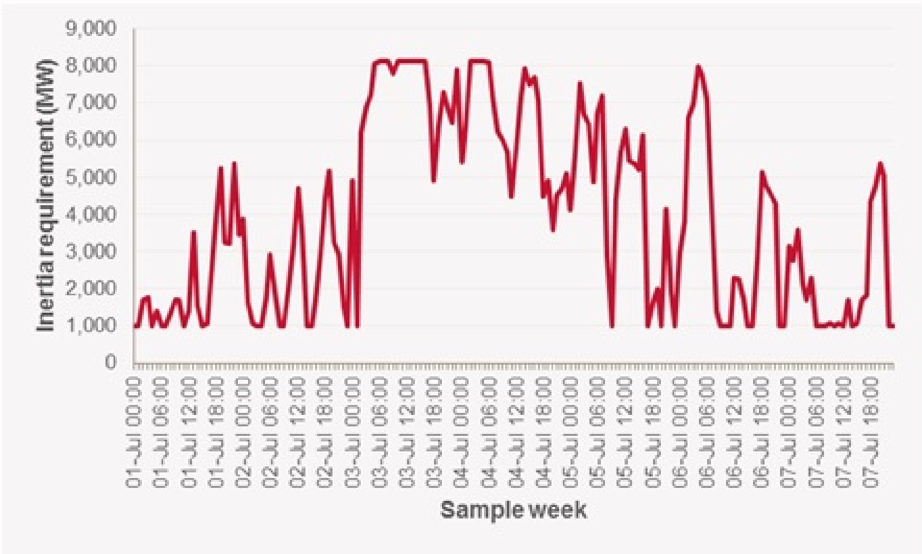


The vertical line on the left represents the absolute minimum system threshold of inertia. This vertical line is a lower bound on the level of inertia that could feasibly be required in order to operate the system within the FOS for a given contingency.

Beyond this level, the sloped line represents the trade-off that exists between the costs of supplying more inertia and the market benefits that could be obtained from running the system in a less constrained manner. However, a continuation of the line shows that any additional inertia supplied to the market beyond an upper bound would have no effect in further alleviating constraints on the system and so provide no additional benefit for either maintaining system security, improving reliability, or lowering the overall cost of energy production.

However, 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 3.2 shows how inertia requirements - in this case, the inertia required to ensure that a RoCoF constraint on an interconnector does not bind - can vary over time depending on the prevailing system and network conditions.

Figure 3.2 Potential variability in inertia requirement for South Australia (assuming 2Hz/s RoCoF limit)



Source: AEMO, submission to the directions paper, p. 7.

Nevertheless, the Commission considers this split in inertia provision between that required to maintain system security and that associated with market benefits to be a useful distinction. Much of the Commission's focus over the course of the review has been on identifying and developing mechanisms to meet these two requirements.

3.2.2 Minimum inertia requirements to maintain system security

The Commission has concluded that the best mechanism to meet the minimum inertia requirements associated with maintaining system security would be through provision by TNSPs. The advantages of TNSP provision include:

- the certainty that would result by TNSPs procuring inertia through network support agreements or themselves providing the required level of inertia through synchronous condensers
- the financial incentives that TNSPs have under network regulation frameworks to minimise the costs associated with their obligations
- consistency with the principle that TNSPs are accountable for outcomes of their networks
- the ability to coordinate inertia provision with the more locational requirements of maintaining system strength, a role that the Commission is also recommending reside with network service providers.

The Commission considered a number of other options, as follows:[46]

46 For a more detailed assessment, please see: AEMC, *System security market frameworks review*, Directions Paper, 23 March 2017, Chapter 3.

- *Generator obligation* - Although a conceptually simple - and intuitively appealing - solution, obliging all generators to provide inertia is unlikely to be efficient. Certainty over the level to be provided would be required at the time of investment, but required levels of inertia can be highly variable and so there would likely be periods when unnecessarily high levels of inertia were provided. Equally, limiting the obligation to only centrally-dispatched generators may be ineffective in the long term as the penetration of distributed energy resources (DER) increases, as inertia could often be required at times when little large-scale generation is dispatched.

- *AEMO contracting* - AEMO contracting for inertia could, like TNSP sourcing, provide the certainty required for investment, while also allowing some flexibility. However, unlike TNSPs which have clear financial incentives, 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. Different parties would be responsible for meeting inertia and system strength requirements.

- *Market sourcing* - A spot market for inertia would not provide the certainty of a contracting approach, and it is not clear that a liquid secondary contract market would develop. The physical properties of inertia would make it difficult to incorporate into the existing dispatch mechanism,[47] which would raise questions as to whether AEMO could effectively instruct generators to provide a given amount of inertia. Again, there would likely be a lack of coordination between the provision of inertia and system strength.

This assessment, and the selected option of TNSP provision, was consulted on in the directions paper. In response, a number of stakeholders supported this approach, suggesting that TNSPs are well positioned to access a range of possible solutions,[48] while others disagreed, contending that TNSPs may have incentives to favour certain solutions or technologies over others.[49]

The Commission agrees that it will be important that the network regulation arrangements do not lead to incentives for TNSPs to act in a way that it is not technology neutral. However, the Commission also considers that the potential costs associated with the risk are relatively low in the context of TNSPs only providing the absolute minimum levels of inertia required to maintain system security. For this reason, and the others set out above, the Commission continues to consider TNSP sourcing to be the preferred approach to the system security component of inertia provision.

47 Inertia is binary, in that a generating unit provides no inertia when it is not running and all of its inertia when is running at any level of energy output. Hence, to dispatch additional inertia would require the commitment of additional plant, a process which would generally take longer than the 5 minute energy dispatch interval.

48 ENA, submission to the directions paper, p. 4; TransGrid, submission to the directions paper, p. 1.

49 ATCO, submission to the directions paper, p. 2; Reach Solar, submission to the directions paper, p. 1; RES, submission to the directions paper, p. 1.

> ***Recommendation 3:*** *Place an obligation on transmission network service providers to provide minimum required levels of inertia, or alternative equivalent services, to allow the power system to be maintained in a secure operating state.*

Draft determination to allocate responsibility for minimum inertia requirements

The Commission is implementing the above recommendation through the *Managing the rate of change of power system frequency* rule change proposed by the South Australian government. A draft rule and draft determination for the rule change have been published concurrently with this report.[50]

A key consideration for the Commission in developing the mechanism through the rule change has been to define what constitutes the minimum required level of inertia. The approach adopted has been to focus on the risks associated with the possible separation of areas of the network into desynchronised islands. Even if the power system is operated in a heavily constrained manner, there will still be a requirement for some level of inertia to be provided if separation is a credible contingency or protected event so that a resulting island could feasibly be operated post-event. The draft rule consequently places obligations on TNSPs in regard to "sub-networks", which are areas of the power system susceptible to islanding, and which could otherwise be operated in an islanded state.

Further details can be found in the draft determination document but, in summary, the main features of the draft rule are:

- An obligation on AEMO to determine sub-networks in the NEM that are required to be able to operate independently as an island and, for each sub-network, assess whether a shortfall in inertia exists or is likely to exist in the future.
- Where an inertia shortfall exists in a sub-network, an obligation on the relevant TNSPs to make continuously available, minimum required levels of inertia, determined by AEMO through a prescribed process.
- An ability for TNSPs to contract with third-party providers of alternative frequency control services, including fast frequency response (FFR) services, as a means of meeting a proportion of the obligation to provide the minimum required levels of inertia, with approval from AEMO.
- An ability for AEMO to enable the inertia network services provided by TNSPs and third-party providers (i.e. instruct them to provide inertia) under specific circumstances in order to maintain the power system in a secure operating state.

The Commission is currently inviting submissions on the draft rule determination, with these being due by 8 August 2017. The final determination is currently scheduled to be made on 19 September 2017.

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50 AEMC, *Managing the rate of change of power system frequency*, Draft rule determination, 27 June 2017.

3.2.3 Inertia provision to realise market benefits

In the directions paper, the Commission explained that its preferred mechanism for the provision of inertia to realise market benefits was for TNSPs to also have responsibility for this. The identification of market benefits would fit well with TNSP planning frameworks, and it would be possible to place financial incentives on TNSPs to drive efficient levels of provision.

Following the publication of the directions paper, the Commission sought to further develop this approach. In doing so, one of the key considerations was the potentially significant variability in inertia requirements. Figure 3.2 above provides an illustration of this, showing that the amount of inertia required to ensure that a RoCoF constraint on an interconnector does not bind can vary by a factor of eight, and over a very short period of time.

With this in mind, the Commission considered two broad options for the design of a TNSP incentive scheme:

- An operational incentive on TNSPs to meet a targeted level of inertia or a targeted proportion of the time when RoCoF constraints should not bind.
- Financially rewarding TNSPs based on actual market outcomes.

However, driven in large part by the variability in the amount of inertia required for this purpose, the Commission has concluded that both options are problematic.

As explained further in chapter 4, the overall efficiency or otherwise of the operational incentive scheme would likely be determined to a much greater extent by the accuracy with which the targeted level of inertia could be forecast than it would be by the ability of the TNSP to efficiently provide this level of inertia. The body setting the target would need to be able to accurately forecast both the likely costs of inertia provision and the resulting benefits. To quantify the benefits would require an ability to accurately forecast market outcomes over the long term. Consequently, the importance of the incentives placed on TNSPs to provide the targeted level of inertia may be somewhat secondary, with the value in designing incentives to efficiently meet a target being questionable if the efficiency of the target is unclear.

An incentive scheme based on actual market outcomes could produce more efficient outcomes by avoiding the above forecasting issues, and incentivising TNSPs to provide additional inertia at times when it was most valued. However, such a scheme would be very complex to design and implement. In addition, and more fundamentally, the scheme would require TNSPs to monitor and participate in the wholesale market in a much more involved way. Its success would rely on TNSPs making real time decisions about committing generation and scheduling inertia to alleviate constraints, a role they have not previously engaged in. It is far from clear that TNSPs would be qualified to undertake this task, or that having them do so would be desirable.

Market-based mechanism to deliver market benefits

In light of the issues of the issues identified with TNSP provision for market benefits, the Commission has re-examined the alternatives.

One of the Commission's key principles is that competition and market signals generally lead to better outcomes than centralised planning, since they are more flexible to changing conditions and to consumers' needs. In this way, competitive market mechanisms are always the Commission's preferred approach. And, in this case, many of the concerns regarding the use of a market sourcing approach for procuring a minimum level of inertia are less of an issue when seeking to realise market benefits.

In particular, while it would be important - but problematic - for AEMO to dispatch inertia to maintain system security, this level of certainty is less important for market benefits. In the presence of a market price for inertia, inertia providers would have an incentive to self-dispatch at times when inertia was valued. Similarly, while the certainty provided by TNSP contracting would potentially be crucial in underpinning investment in inertia to maintain system security, this again would be less critical where the objective is to realise additional market benefits.[51]

The Commission has therefore come to a view that a market-based mechanism is likely to be a more appropriate mechanism to use to deliver market benefits, and would have significant advantages in that wholesale market participants - rather than TNSPs - would continue to make generator commitment decisions. By taking inertia prices into account in their energy market offers, participants would effectively co-optimise inertia provision with the energy (and FCAS) market. Increases in the expected inertia price would incentivise greater provision, and this market signal - which would be provided to all market participants - should allow the costs and benefits of inertia provision to be efficiently balanced.

To achieve this aim, the Commission has identified and begun to develop a market mechanism to provide inertia payments associated with inter-regional RoCoF constraints. This is described in more detail in chapter 4.

> ***Recommendation 4:*** *Introduce a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum obligation on transmission network service providers.*

Implementation of the market sourcing mechanism to realise market benefits

In the directions paper, the Commission indicated that a mechanism to guide the provision of inertia to realise market benefits would be part of a "subsequent package" of reforms to be implemented approximately three years after the more immediate measures identified. However, since then, the Commission has reached the view that a

51 Although, as described in chapter 4, the Commission has identified a market mechanism where there would be some incentive for some market participants to contract with inertia providers.

mechanism to provide market benefits would be an important complement to the TNSP-based mechanism that would deliver only an absolute minimum level of inertia for system security reasons.

Accordingly, the Commission has considered how the market benefits mechanism could be implemented more quickly, and has concluded that it would be possible to do so through the *Inertia ancillary service market* rule change proposed by AGL. While this rule change sought to be implement arrangements based around long term contracting by AEMO, its objective was to provide a mechanism to reflect the value associated with inertia to providers of that service. As such, the Commission considers that it would be appropriate to implement a more preferable rule that seeks to achieve the same objective as part of that rule change.

Unlike the rule changes associated with recommendations 1 and 3, the Commission is not yet in a position to make a draft determination for this rule change. The preferred mechanism has been identified since the directions paper, and requires further development and consultation. While it is likely to be less complex to implement than a TNSP incentive scheme, there will still be a considerable amount of detail to work through in order to develop a draft rule. The mechanism will need careful design due to the potential impacts on the operation of the energy and ancillary services markets.

In light of this, the Commission has made a decision under s.107 of the NEL to extend the period of time to make the draft determination until 7 November 2017. However, implementation of the final rule could still be expected to be relatively proximate to implementation of the mechanism to provide minimum levels of inertia for system security purposes.

3.3 Better frequency control

As discussed in chapter 2, in the long term, the most efficient response to the emerging frequency control issues is likely to be a combination of mechanisms to procure inertia (to reduce the rate at which frequency changes in response to a disturbance) and the provision of FFR services, which will be able to rebalance supply and demand more quickly than existing FCAS services. However, over the course of the review, a number of stakeholders have expressed a strongly held view that the existing arrangements for frequency control should be reviewed before additional services are designed and implemented.[52]

In response to these concerns, AEMO has begun a program of work to investigate frequency performance in recent years, to diagnose any problems and to understand the potential impacts of these.

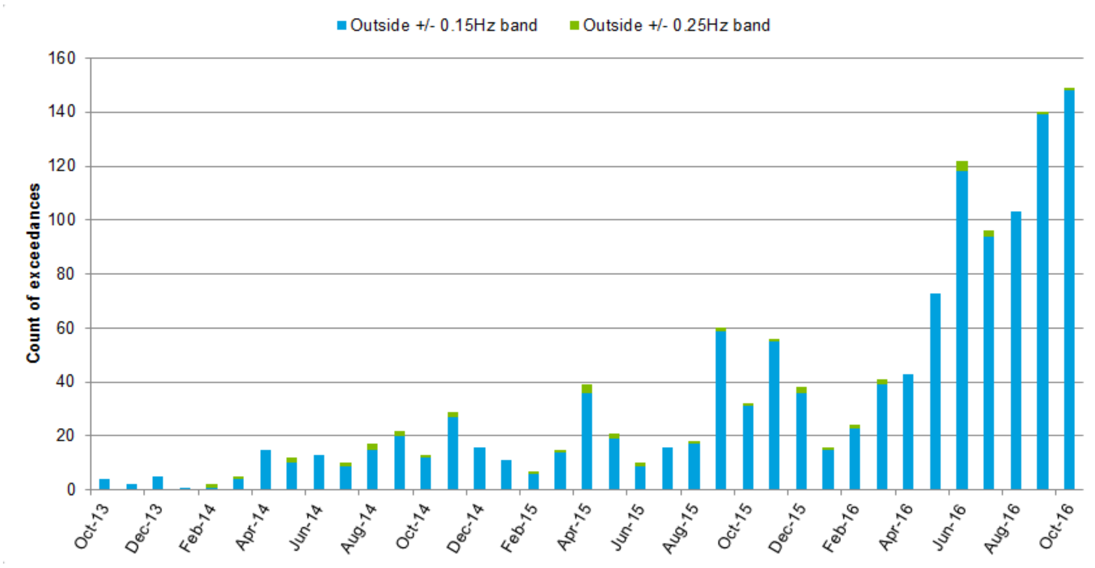
This work, being undertaken in consultation with AEMO's Ancillary Services Technical Advisory Group (AS-TAG), suggests that, in recent years, system frequency has become increasingly less tightly held to 50Hz within the normal operating frequency band (49.85Hz to 50.15Hz). There has also been an increase in the number of relatively

52 CEC, submission to the directions paper, p. 3; Pacific Hydro, submission to the interim report, p. 1.

small excursions outside the normal operating frequency band. However, similar increases have not been observed in large (>0.25Hz) deviations.[53]

The following chart highlights this frequency performance decline, with the number of mainland frequency band exceedances showing a clear increasing trend.

Figure 3.3 Mainland number of frequency band exceedances



The key concern with this increase in frequency variation is that it has the potential to create system-wide issues, including:

- damage to synchronous plant - due to rapid changes in loading
- loss of system resilience - increased likelihood of adverse security outcomes following a contingency event
- difficulty in re-synchronising separated areas due to varying frequency.

The causative factors leading to this situation are not clearly understood at this time but possible contributing factors include:

- change in governor controls:
  - lifting of mandatory response requirement in 2001
  - introduction of digital governors and associated ease of disabling the governor.
- change in generator behaviour:
  - commercial drivers including a desire to operate plant in more fuel efficient way, and wanting to avoid wear and tear on plant
  - concern that providing governor response may result in a risk of the AER finding a non-compliance in the following of dispatch instructions.

53 AEMO, AS-TAG: Frequency Performance, 3 May 2017, slide 4.

Box 3.1 Governor response in the NEM and FCAS

A governor is a device to regulate the speed of a machine, such as a generating unit. When the NEM began operation in 1998, all generating units over 100MW were obliged to have governors that responded to changes in system frequency, outside of specified, relatively tight deadbands.

At the start of the market, ancillary services were procured through a tender process and long term contracts between NEMMCO[54] and service providers.[55] Notably, these contracts ensured the availability of the service (for instance, by ensuring that sufficient generators had "headroom" to provide a response above their dispatch targets), but all generators were mandated to provide a governor response to the extent that they were able to.

Following the Ancillary Service Review undertaken by NEMMCO, the existing spot markets were introduced for the enablement of contingency FCAS (i.e. to ensure their availability). However, at the same time, the requirements for mandatory response by generators not enabled to provide FCAS were removed.

The removal of the requirement for mandatory response was not therefore an inherent result of introducing FCAS markets - the spot markets for enablement simply replaced the previous contracting approach. It would have been possible to continue to impose the mandatory response obligation. However, in its review, NEMMCO also recommended that this obligation be removed. The justification for the recommendation was that mandatory provision represented a "hidden subsidy" and that "governor capability should be fully paid for under the FCAS arrangements proposed".[56]

The Commission understands that the lack of mandatory response obligations in the NEM is unusual.[57] In the USA, concerns around degrading frequency control have led the Federal Energy Regulatory Commission (FERC) to indicate recently that it is likely to introduce a nationwide requirement on all new connecting generators, both synchronous and non-synchronous, to install and operate a functioning governor or equivalent controls. In a notice of proposed rulemaking, FERC explained that it considered this justified, in order to maintain adequate frequency performance, and reasonable, given that it would impose only low costs.[58]

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54 The National Electricity Market Management Company (NEMMCO) was a predecessor to AEMO.

55 NEMMCO, *Ancillary Service Review - Recommendations*, Final Report, 15 October 1999, p. i.

56 Intelligent Energy Systems, *Who should pay for ancillary services?*, A project commissioned by the NEMMCO ancillary services reference group, Final report, July 1999, p. 48.

57 For example, in Great Britain all generators subject to the Grid Code are required to provide mandatory frequency response (CC 6.3.7).

58 FERC, *Essential Reliability Services and the Evolving Bulk-Power System - Primary Frequency Response*, Notice of proposed rulemaking, 17 November 2016, pp. 30-36.

These issues may be material especially at a time when the general resilience of the system is decreasing due to greater penetration of non-synchronous generation and the retirement (and risk of retirement) of synchronous thermal generation plant. To the extent that governors are being disabled or overridden, a further implication would be that the accuracy of power system simulation studies will reduce. This may further affect AEMO's ability to effectively manage system security.

As part of its program of work to investigate this issue, AEMO has commissioned DigSilent, an international consultancy specialising in power system management, to undertake an assessment to:[59]

- investigate the cause or causes
- investigate the consequences.

It is currently anticipated that the findings of this assignment will be presented to the AS-TAG in July 2017.

The Commission notes that, should the outcome of this work suggest that mandatory governor response requirements be reintroduced, there are a number of potential consequential impacts that will also need to be considered.[60] These include the potential concerns already noted that providing governor response may result in a risk of the AER finding a non-compliance in the following of dispatch instructions.

In a submission to this review, Stanwell noted that the AER had entered into an undertaking with CS Energy,[61] following an investigation. Stanwell suggested that, as a result of the setting on its units, CS Energy was providing frequency response despite not having been enabled to provide FCAS, and that this led it to deviate from its dispatch targets. Since the investigation, Stanwell contended, multiple generators have changed their settings so as to prevent automatic deviations in response to changes in system frequency, and this has resulted in less inherent automatic frequency control in the NEM.[62]

In addition, the costs associated with the provision of regulation FCAS are recovered on a "causer-pays" basis. This is intended to attribute these costs to those market participants who have contributed most to frequency deviations in the recent past. Consequently, in the event of the introduction of a mandatory governor response

59 DigSilent, *Frequency regulation analysis*, Proposed approach, 3 May 2017, slide 10.

60 The Commission notes that the Reliability Panel will be undertaking a review of the FOS and considering, in particular, whether the settings within the FOS remain appropriate in light of the changing generation fleet and the various system security work programs of the AEMC and AEMO addressing related frequency issues. An issues paper is expected to be published in July 2017. http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Frequency-Operating-Standard

61 The undertaking is available at https://www.aer.gov.au/wholesale-markets/enforcement-matters/infringement-notices-issued-to-cs-energy-and-enforceable-undertaking-failure-to-follow-dispatch-instructions-and-offer-obligations

62 Stanwell, submission to the consultation paper, pp. 2-3.

requirement on generators, it will be important to ensure that the causer-pays methodology does not place counter-acting financial incentives on participants.

> ***Recommendation 5:*** *Assess whether mandatory governor response requirements should be introduced and investigate any consequential impacts (including on the methodology for determining causer pays factors for the recovery of regulation FCAS costs).*

3.3.1 Frequency control frameworks review

To progress a number of recommendations it is making in this review, in July 2017 the Commission will initiate a review into market frameworks necessary to support better frequency control: the *Frequency control frameworks review*.

The review will first consider the outcome of AEMO's work on recent frequency control performance and its implications. The purpose of the review in this regard will be to provide a vehicle for any framework changes required to address these immediate issues to be progressed.

However, the review will also allow a more fundamental, longer-term reassessment of FCAS frameworks to be undertaken.

As explained further in chapter 5, the objective of this work will be to determine how to most appropriately incorporate FFR into FCAS markets. Although FFR could currently be procured as a six second ("fast") FCAS contingency service, this would not necessarily recognise any enhanced value that might be associated with the faster response. Consequently, one approach that might be considered would be to introduce some form of differential pricing within the existing fast service (see section 5.3 for more detail).

The NER only provides high level descriptions of FCAS services and requires that AEMO prepares a market ancillary services specification (MASS) containing a detailed description of each service, including the fast contingency service. Adopting some form of differential pricing approach would, therefore, require changes to be made to the MASS, but may also require limited modifications to the NER.

The Commission understands that AEMO's work program, commenced through the FPSS program, will continue but is likely to reflect a broader approach to meeting future power system challenges. Consequently, this may provide an appropriate vehicle for AEMO to further assess if and when such a development might be required, and to consider potential changes to the MASS and to its systems to implement such a change. The Ancillary Services Technical Advisory Group would allow for ongoing consultation with the relevant technical experts from industry. Any required changes to the rules could be developed by the Commission through the *Frequency control frameworks review*.

However, the *Frequency control frameworks review* will also offer the opportunity to consider wider questions as to whether existing FCAS markets will remain relevant in terms of meeting the emerging needs of frequency control in the NEM. This, might for instance, include reconsidering the rationale for the specific services that currently exist, in addition to considering the case for additional services.

Going forward, FCAS may also increasingly need to be optimised against dynamic system characteristics, such as the presence of inertia in each dispatch interval. The mechanisms for providing inertia recommended in this report are predominately targeted at addressing the risk associated with network separation, as this is where the immediate issues currently lie. However, as levels of inertia decline into the future, a level of inertia will be required to manage contingencies across the NEM as a whole (e.g. loss of the largest generator). Consequently, any long term review of FCAS markets will need to consider how inertia provision can best be co-optimised against FCAS, with this potentially requiring the development of additional inertia services.

The issues for consideration through such a review of FCAS markets are discussed in more detail in section 5.4. The *Frequency control frameworks review* will allow the Commission to also consider these more fundamental aspects of existing FCAS markets. This work would be supported in a technical capacity by AEMO's future work program.

Recommendation 6: *Review the structure of FCAS markets, to consider:*

- *any drivers for changes to the current arrangements, how to most appropriately incorporate FFR services, or alternatively enhancing incentives for FFR services, within the current six second contingency service; and*
- *any longer-term options to facilitate co-optimisation between FCAS and inertia provision.*

Ramping

The *Frequency control frameworks review* will also allow the Commission to consider matters beyond the priority power system issues previously identified by AEMO and assessed in this review.

A particular further issue related to frequency control that will be examined through the *Frequency control frameworks review* relates to ramping requirements. As the installed capacity of solar PV continues to increase, the net operational demand[63] curve in the NEM will change. Demand during the middle of the day will get progressively lower, and the slope of the demand curve in the ramp-up to the evening peak will get steeper.

To effectively meet the resulting increased ramping requirements will require flexible generation capacity. However, new intermittent renewable generation is expected to continue to displace dispatchable thermal generation, potentially reducing the capacity of the power system to meet the increasingly variable demand patterns.

63 Net operational demand in this context means demand met by the national grid. As generation by domestic solar PV "behind the meter" increases, net operational demand decreases.

The Commission intends to use the *Frequency control frameworks review* to identify any required changes to existing market and regulatory arrangements to address this issue, which would complement AEMO's consideration of the technical challenges and possible technical solutions through its future work program.

> ***Recommendation 7:*** *Assess whether existing frequency control arrangements will remain fit for purpose in light of likely increased ramping requirements, driven by increases in solar PV reducing operational demand at times and therefore leading to increased demand variation within a day.*

3.3.2 Technical obligation to have frequency response capability

Through the review, the Commission has explored the role of technical obligations in providing the capability for new services to be offered. The Commission's view is that, where this would not impose undue costs, this would act as a useful complement to the service procurement mechanisms discussed previously.

In the directions paper, the Commission set out, as part of its proposed package of immediate measures, a potential obligation on new non-synchronous generators to have the capability to provide FFR. The Commission has since given this issue further consideration, and has modified its approach. However, it continues to consider that a new technical obligation would be beneficial.

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

In putting the proposal forward in the directions paper, the Commission did not expect the obligation on non-synchronous generators to be an onerous requirement,[64] although it was not proposed to be applied to existing non-synchronous generators due to concerns that retrofitting FFR capabilities to existing generators would likely be much more expensive than including the capability during the initial installation stage. This approach received support from a number of stakeholders,[65] although others considered that provision of this capability should not be mandated but, rather, incentivised by the procurement of these services.[66]

64 GE Energy Consulting suggests that the capital costs for inclusion of FFR capability in new plant is expected to be of 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.

65 Origin, submission to the directions paper, p. 2; South Australian government, submission to the directions paper, p. 4; South Australia Council of Mines and Energy, submission to the directions paper, p. 5; Tesla, submission to the directions paper, p. 4;

66 AEC, submission to the directions paper, p. 2; Engie, submission to the directions paper, p. 5; SACOSS, submission to the directions paper, p. 1.

However, there are a variety of forms of FFR that can be provided by different technology types, and the Commission has therefore concluded that it is problematic to define an obligation in a technology neutral way. It has been suggested that the best approach is to specify generic technical obligations that are not designed in terms of specific services but rather in terms of enablement of active power injection and control capabilities consistent with whatever technology is being adopted.

This issue has been acknowledged by AEMO in its advice to ESCOSA on technical standards for generator licensing in South Australia. AEMO recommended that ESCOSA require all new generation (both synchronous and non-synchronous) seeking to connect in South Australia to have active power control capabilities, such that their active power output can be made automatically sensitive to system frequency or be directly controlled over short timeframes. In AEMO's view this recommendation is "broadly compatible with FFR provision from generators, without prescribing at this time specifically how these responses must be delivered".[67]

The approach recommended by AEMO to ESCOSA may offer a framework that can be adopted within the NER, and is discussed in more detail in section 6.2. Similar to the recommendation that new inverter-based generation should be required to operate at a minimum short circuit ratio, the forthcoming rule change on generator performance standard announced by AEMO following its South Australian work will offer the opportunity to consider the incorporation of an active power generator obligation into the NER.

> ***Recommendation 8:*** *Consider placing an obligation on all new entrant plant, whether synchronous or non-synchronous, to have fast active power control capabilities.*

3.4 Facilitating the transformation

Through this review, the Commission has considered the priority power system security issues highlighted by AEMO in its *Future Power System Security Program* and, before that, identified by AEMO's Power System Issues Technology Advisory Group (PSI TAG).

A number of other potential challenges were also identified by PSI TAG and, although these were considered to be a lower priority initially, there is a need for these further issues to be considered over time.[68] Such future issues would likely include:

- **System restart** - To date, only conventional thermal and hydro generation have provided system restart ancillary services (SRAS). Although rarely called upon, the ability to restart the system is clearly of crucial importance. However, the requirements placed on providers may mean that other forms of generation has either not been incentivised or capable of providing the services. This is

67 AEMO, *Recommended technical standards for generator licensing in South Australia*, 31 March 2017, p. 35.

68 AEMO, *Future Power System Security Program*, Progress Report, August 2016, Appendix A.

particularly true if the system is weak, with low fault levels which affect the ability to re-energise the network.

- **Reduction in voltage control** - Synchronous generating units are an important source of dynamic voltage support. The displacement of synchronous generation could result in local control issues, placing pressure on existing arrangements. New sources of dynamic voltage control, including from distributed energy resources, may be required.

In the first instance, the task of continuing to monitor and scope these technical issues is likely to best be accommodated through AEMO's future work program. When this is further advanced, it may then be appropriate for the Commission to undertake its own work on the market and regulatory implications of these additional challenges.

Recommendation 9: *Continue to scope further power system security issues likely to arise from the ongoing transformation of the market, such as:*

- *the impact on system restart ancillary services of decreasing levels of synchronous generation; and*
- *the adequacy of current voltage control arrangements.*

4 The provision of inertia to realise market benefits

Box 4.1 Summary of chapter

To complement the draft rule to impose obligations on TNSPs to provide a level of inertia associated with maintaining system security, the Commission considers that it will be important to also introduce a mechanism to provide inertia additional to the minimum secure level to allow for greater power transfer capability across the network, resulting in market benefits.

To develop such a mechanism, the Commission considered various designs for TNSP incentive frameworks, which would aim to reward TNSPs for the provision of additional inertia where this resulted in market benefits. This chapter discusses the issues that the Commission encountered, and how these have prompted it to instead investigate an alternative, market-based mechanism, which now forms the Commission's preferred approach.

- ***Recommendation 4:*** *Introduce a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum obligation on transmission network service providers.*

The specific mechanism the Commission has been developing, and which is presented in this chapter, features an inertia price paid to inertia providers based on the value associated with relieving inter-regional RoCoF constraints. To implement such a market benefits mechanism as soon after the system security obligations as possible, the Commission has decided to progress this mechanism through the *Inertia ancillary service market* rule change proposed by AGL. The Commission has extended the period of time available to make the draft determination for the rule change to allow for careful consideration of the detailed issues involved and potential impacts on the operation of the market.

4.1 Introduction

As explained in chapter 3, there is a level of inertia associated with maintaining system security, as well as an additional level which would allow for greater power transfer capability in the network resulting in market benefits. Concurrently with this report, the Commission has published a draft determination for the *Managing the rate of change of frequency* rule change, which would introduce the obligation on TNSPs to provide a minimum level of inertia for system security purposes.

Above the minimum level, there will be a trade-off between the cost of providing additional inertia and improving the power transfer capability of the network. That is, allowing for greater output from generators and increased energy flows on the network to provide market benefits for consumers. However, at present there is no such mechanism to guide the efficient provision of inertia in real time to provide market benefits, nor is one included in the draft rule for the *Managing the rate of change of frequency* rule change.

In the directions paper, the Commission acknowledged the benefits of such a mechanism, and explained that its preferred mechanism for the provision of inertia to realise market benefits was for TNSPs to also have responsibility for this. The identification of market benefits would fit well with TNSP planning frameworks, and it would be possible to place financial incentives on TNSPs to drive efficient levels of provision.

Since the directions paper, the Commission has sought to further develop the intended TNSP sourcing approach, which would reward TNSPs through an incentive framework for the delivery of market benefits from providing additional inertia. However, this experience has prompted the Commission to consider and develop an alternative, market-based approach, where an inertia price would be paid to inertia providers based on the value associated with relieving inter-regional RoCoF constraints.

This chapter explains both of these mechanisms in more detail, and sets out the Commission's reasons for recommending that the market sourcing approach be considered further for implementation.

4.2 TNSP sourcing approach

In the directions paper, the Commission outlined the possibility that a TNSP incentive framework could be developed to guide the procurement and dispatch of, and investment in, inertia to provide market benefits. It was envisaged that, under this framework, TNSPs would be rewarded for the delivery of additional inertia that allowed for greater power transfer capability in the network.

4.2.1 Design options for a TNSP incentive scheme

In seeking to develop the proposed incentive framework, the Commission considered two broad options:

- Incentivising TNSPs to meet a targeted level of inertia or a targeted proportion of the time when RoCoF constraints should not bind.
- Financially rewarding TNSPs based on actual market outcomes associated with less constrained generation dispatch and energy flows.

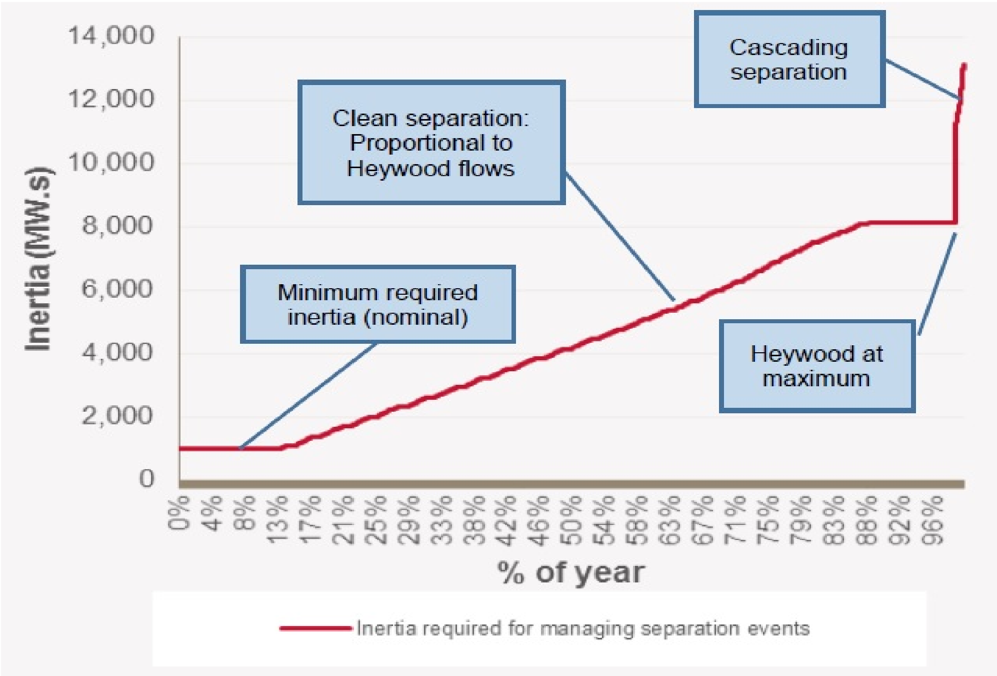
Operational scheme to meet a target level of unconstrained operation

Under the first option, a target level would be set by either the TNSP or by an independent body, such as AEMO or the AER. The target could be expressed as either a fixed level of inertia required or, more likely, as a proportion of the time when RoCoF constraints should not bind. In its submission to the directions paper, AEMO described a potential *system standard for inertia*, which would require that "the system operates without inertia-related constraints binding a least a certain percentage of the time".[69]

[69] AEMO, submission to the directions paper, p. 10.

However, deriving an efficient target would not be straightforward. The figure below shows an inertia duration curve, which stacks the inertia required to ensure that RoCoF constraints do not bind on the Heywood interconnector in increasing size order over the course of a year.[70] As can be seen, the inertia requirement increases on a linear basis over the course of much of the year, and there is no obvious amount of inertia that should be provided.

Figure 4.1 Inertia duration curve (assuming 2Hz/s RoCoF limit)



Source: AEMO, submission to the directions paper, p. 5.

Consequently, setting an efficient target would require economic modelling to determine the expected efficient market outcome (i.e. to assess where on the line would be the optimal point on a cost-benefit basis). Modelling would need to assess a range of scenarios representing different combinations of generator dispatch patterns and system and network conditions which would likely result in binding constraints. Under each scenario, the likely level of additional inertia which would alleviate a constraint resulting in reduced costs to consumers would form the basis for the target. Modelling would require input from AEMO and industry participants.

Once the target was set, the incentive reward or penalty would be calculated by comparing the TNSP's performance (i.e. the percentage of time that inertia-related constraints did not bind) against the targeted level. This would place a portion of the TNSP's revenue 'at risk', depending on its performance.

Given that the target would be assumed to represent the optimal level (as best it could be calculated), TNSPs should not be rewarded for exceeding the target - this would

70 In the figure, a "clean separation" is the non-credible loss of both Heywood circuits. A "cascading separation" is the non-credible loss of multiple generators in South Australia, which would cause the interconnector to overload and trip.

represent an over-provision of inertia. Rather, performance should be measured based on deviation from the target. While this would tend to imply a scheme based around penalties only, a TNSP could potentially be rewarded if it out-performed some "breakeven point" (e.g. if the TNSP was only two per percentage points away from the target and the breakeven point was five percentage points, it would earn a reward). This design could be similar to some of the existing components of the Service Target Performance Incentive Scheme (STPIS).

Box 4.2 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 component – seeks to reduce the number of unplanned network outages and restore service following supply interruptions
- Market impact component (MIC) – aims to encourage TNSPs to minimise the effect of network outages on wholesale price
- Network capability component (NCC) – designed to encourage TNSPs to develop incremental operational and capital expenditure projects to improve the capability of the network.

The MIC 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 a network outage 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.

Under the NCC, TNSPs submit a Network Capability Incentive Parameter Action Plan (NCIPAP) as part of their revenue proposals. NCIPAPs consist 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 transmission capability.

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.

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.

Financial rewards based on actual market outcomes

An alternative to setting ex-ante targets would be to reward TNSPs based on actual market outcomes, and the Commission has investigated how such a mechanism could be designed.

The scheme would be reliant on being able to quantify the value associated with inertia provision. An important part of this calculation would therefore be deriving the shadow price for inertia from the RoCoF constraint, as described in box 4.3.

Box 4.3 A shadow price for inertia

For every dispatch interval in the energy market, AEMO derives dispatch using the National Electricity Market Dispatch Engine (NEMDE) to bring supply and demand into balance.

An output, or by-product, of solving the dispatch program is the energy price for each region. The energy price is the value of the next unit of electricity available to be supplied to that region for that dispatch interval. It is the marginal cost of the constraint that supply must equal demand.

Prices can be derived from other constraints in the dispatch process as well. The 'shadow price' is equal to the marginal cost of a constraint, i.e. how much money could have been saved if the constraint were relaxed by a very small amount.

In the presence of RoCoF constraints, which are limited by the amount of inertia present, this principle can be applied to determine a price for inertia. In the case of South Australia, the critical constraint related to inertia is given by:

(25[Hz] x Heywood Flow [MW])/(RoCoF [Hz per second])≤Inertia [MWs]

Assuming that a hypothetical 1 MW.s (or simply a very small) provider of inertia is included in the system, taking the shadow price of this constraint would yield a price for inertia equal to its marginal value.

In other words, given a RoCoF limit, the incremental value of inertia could be determined by the value of an incremental increase in the flow on the Heywood Interconnector, i.e. the value of inertia relates to the difference in the regional reference prices between South Australia and Victoria.

When a RoCoF constraint bound, the resultant cost would be the shadow price multiplied by the amount of inertia required to unbind the constraint. The Commission understands that it would be possible to derive this amount through ex-post analysis to infer the amount of inertia that would have been required to relieve the RoCoF constraint to the level of the next binding (non-RoCoF) constraint.[71]

If RoCoF constraints never bound (because there was always sufficient inertia), they would therefore not act to limit network flows. However, where a RoCoF constraint bound, there would be an inertia "shortfall" - the value of which could be quantified economically from the shadow price and the amount of inertia required.

An incentive scheme would aim to have TNSPs minimise overall costs, both those of providing the inertia and those associated with inertia shortfalls, and therefore efficiently balance the two. This incentive could be given either by directly exposing TNSPs to these costs or, as with the operational incentive option described previously, rewarding or penalising TNSPs by comparing their performance against a "breakeven" target set by the AER.

4.2.2 Assessment of TNSP provision approach

In developing the above options, it became clear that both were problematic. Under the operational scheme, the body setting the target would need to be able to accurately forecast both the likely costs of inertia provision and the resulting benefits. To quantify the benefits would require an ability to accurately forecast market outcomes over the long term. TNSPs would then be obliged or incentivised to provide the targeted level of inertia, even if these forecasts turned out to be incorrect. The costs associated with any forecasting errors would be borne by consumers.

Hence, under this first approach, the TNSP incentives to provide the targeted level of inertia would be somewhat secondary, with the value in designing incentives to efficiently meet the target being questionable if the efficiency of the target itself is unclear.

A TNSP incentive scheme based on market outcomes would likely result in more efficient outcomes by avoiding the above issues and incentivising TNSPs to provide additional inertia at times when it was most valued.

However, the scheme would be very complex to implement and calibrate. Beyond the complexities already set out, a particular issue is that it would likely be difficult to balance the incentives between investment (i.e. in synchronous condensers) and operational measures (such as procurement from generators).

More fundamentally, the scheme would require TNSPs to monitor and participate in the wholesale market in a much more involved way. Its success would rely on TNSPs making real time decisions about committing generation and scheduling inertia to alleviate constraints, a role they have not previously engaged in.

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71 For inter-regional constraints, the analysis could also consider the level at which inter-regional prices would have converged. The lower of the two changes in flow would be used to determine the inertia shortfall.

The scheme would be the only mechanism for realising the value associated with the provision of inertia - generators providing uncontracted inertia by being dispatched in the energy market would not be rewarded. Given this, there would therefore be a driver for all inertia providers to seek TNSP contracts. In this way, TNSPs may end up making commitment decisions in real time for a significant proportion of synchronous generators.

In submissions to the directions paper, a number of stakeholders questioned whether TNSPs would be well-qualified to undertake such a task. In particular, Engie suggested that TNSPs "have little need to contend or interact with the competitive market elements of the NEM", and that it would be "a difficult task for regulated TNSPs to assess and understand competitive drivers on NEM participants, let alone forecast how such drivers might play out over the medium to longer term".[72]

4.3 Market sourcing approach

Given the difficulties associated with a TNSP sourcing approach, since the directions paper the Commission has identified and developed a market sourcing approach as a potential alternative option to guide the provision of additional inertia for market benefits.

The Commission understands that, in the near future at least, RoCoF constraints are most likely to be applied on an inter-regional basis and, that by restricting flows between regions, these constraints are likely to have the greatest economic impacts. As the value of additional inertia to alleviate inter-regional RoCoF constraints is related to the reduction in price separation between two regions, the Commission is considering the possibility of remunerating inertia provision by using the inter-regional settlement residues (IRSR) that accrue on interconnectors.

4.3.1 Design of a market sourcing approach

Inter-regional price separation occurs when interconnector capacity is limited and therefore insufficient to equalise the spot price by allowing enough power to flow from a lower to a higher priced region. If network conditions allow it, electricity flows from a lower price region toward a higher priced one. In an unconstrained network, with unlimited capacity, this would result in perfectly coupled prices in all regions, altered only by network losses. However, there is congestion in the NEM, and interconnectors do not always have enough capacity to allow for the equalisation of prices across regions.

In such cases, AEMO collects more money in the higher priced region (from consumers) than it needs to pay for the generation that has flowed from the lower priced region. The difference between the price paid in the importing region and the price received in the exporting region, multiplied by the amount of flow, is called an inter-regional settlements residue (IRSR).

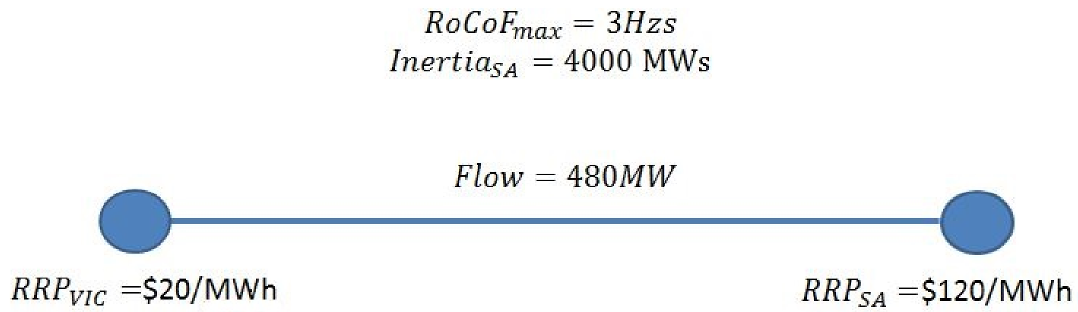
72 Engie, submission to the directions paper, p. 2.

Where an inter-regional RoCoF constraint binds, the IRSR is equal to the shadow price of inertia (as discussed in box 4.3) multiplied by the amount of inertia in the constrained region. This is because the provision of an additional MW.s of inertia would allow an additional amount of inter-regional transfer, and hence the shadow price of inertia is derived from the inter-regional price separation in the same way that the shadow price of the constraint would be for any other type of constraint.

As an example, in the presence of 4000MW.s of inertia in South Australia, a RoCoF constraint on the Heywood Interconnector would bind at a flow of 480MW. Assuming the price separation between South Australia and Victoria is $100/MWh (and ignoring losses), the price of inertia can be calculated as:

$$\frac{480MW \; x \; \$100/MWh}{4000MWs} = \$12/MWs/h$$

Figure 4.2



Under the proposed mechanism, the IRSR funds accruing as a result of RoCoF constraints would be paid to inertia providers. Unlike the TNSP sourcing approach, all inertia providers would be eligible to provide the services, and would receive payments from settlement.

These payments would act as a signal to guide the dispatch of inertia in the short term, and investment over the longer term. There would not be a separate inertia market, rather market participants would take expected inertia payments into account in structuring their energy market offers. Generators dispatched in the energy market who were providing inertia would receive inertia payments in addition to energy market payments.

At times of plentiful inertia, RoCoF constraints would not bind, there would be no inter-regional price separation and, hence, the inertia price would be zero. However, when RoCoF constraints bound, there would be a positive inertia price which would act to signal the value of inertia and encourage participants to provide additional inertia where the expected proceeds would exceed the marginal cost involved in doing so.

4.3.2 Assessment of market sourcing approach

The Commission has come to a view that a market-based mechanism would have significant advantages in that wholesale market participants - rather than TNSPs - would continue to make generator commitment decisions. By taking inertia prices into account in their energy market offers, participants would effectively co-optimise inertia provision with the energy (and FCAS) market.

A market-based mechanism would offer an open and transparent approach that would best facilitate competition in the provision of inertia. As compared to TNSP sourcing under an incentive framework, it would also be flexible in that it would allow the level of the service to vary over time to adapt to changing market conditions. Increases in the expected inertia price would incentivise greater provision, and this market signal - which would be provided to all market participants - should allow the costs and benefits of inertia provision to be efficiently balanced.

Further, while implementation would not be trivial, much of the framework for pricing and settlement is already in place, and it is likely to be less complex than developing a TNSP incentive scheme based around targeting efficient market outcomes.

However, the mechanism discussed here could have some drawbacks. Firstly, a mechanism using IRSR funds to pay inertia providers would only work for contingencies involving inter-regional separation. It would not provide a source of funding for RoCoF constraints associated with intra-regional separation. To the extent that such risks became a material issue, a separate mechanism would be required to procure inertia on a sub-regional basis to efficiently respond to any intra-regional constraints.

While a market mechanism such as this would be more flexible, it might equally provide less certainty. The presence of a market price for inertia would offer inertia providers an incentive to self-dispatch at times when inertia was valued but there would be no certainty over either dispatch in the short term or investment in the longer term.

Unlike the contracts offered by TNSPs for system security purposes, there would be no primary contracting for market benefits and it is not clear that a secondary contracting market would develop and guide investment in the same way that it does in the energy market.

In addition, a key issue would be the impact of using the IRSR funds on the existing settlements residue auctions (SRA). By using the IRSRs in this way when RoCoF constraints bound, a "gap" would be created in the value of SRA units and potentially degrade the effectiveness of these, to the extent that they are currently used as hedge against inter-regional price risk.

Box 4.4 Settlement residue auctions

Price separation between regions of the NEM creates risk for parties that contract across those regions. This risk is equal to the price difference between the regions multiplied by the volume of the contract.

To offer participants an opportunity to manage this risk, AEMO auctions the rights to the IRSRs - which represent the price difference multiplied by the total flow between the regions. In these settlement residue auctions (SRAs), SRA units, representing a right to a certain portion of the IRSR, are offered to auction participants. Once the auction is completed, the settlements residue is distributed among successful auction participants proportionally to the number of units they have purchased.

AEMO forwards the auction proceeds to the TNSPs located in the importing regions. Those TNSPs then pass these proceeds to consumers in the form of reduced transmission use of system charges.

One SRA unit represents a nominal MW of capacity and would provide a firm hedge if flows in MW on the relevant interconnector were equal to the number of units auctioned. However, the firmness of a SRA hedge is often uncertain and volatile as flows can be constrained below this level, due to factors such as intra-regional generator bidding behaviour and network outages.

4.3.3 Issues for further consideration

While the Commission is of the view that the mechanism outlined above offers considerable promise, there are a number of issues that require further consideration and development.

With regards to the key issue of the impact on the effectiveness of SRA units, the Commission notes that one option for protecting against this could be for purchasers of SRA units to also enter into contracts with recipients of inertia payments: an "inertia hedge". By entering into the two instruments, purchasers would receive a stream of payments from the SRA units when non-RoCoF constraints bound and from the inertia hedge when RoCoF constraints bound.

The sale of inertia hedges by inertia providers could also act as a valuable signal to guide investment in inertia over the long term. To the extent that secondary trading in derivatives contracts was established, this would address concerns that a spot price for inertia by itself would give insufficient certainty to underpin investment.

The other major issue for further consideration would be the participation of TNSPs in the market mechanism. To the extent that TNSPs provided inertia, for instance through the operation of synchronous condensers, this would result in funds accruing in settlement, raising the question as to whether these funds should be distributed to the TNSPs.

However, the participation of regulated entities in competitive markets can often raise concerns. While these concerns can sometimes be addressed by ring-fencing the part of the business providing the competitive service from the regulated entity, that may be problematic in this case, as the assets may already be funded on a regulated basis (for instance, to provide system strength or meet the minimum inertia requirement).

A practical solution may to treat these assets in exactly the same manner as other TNSP assets facilitating inter-regional power flows. These assets are currently funded on a purely regulated basis and the funds they attract in settlement - the IRSRs - are auctioned off to participants. In this way, AEMO could also auction inertia payments accruing to TNSPs in the same way as it currently auctions IRSRs.

Such an approach would both resolve any concerns associated with the participation by regulated entities in a competitive market and also readily allow purchasers of SRA units access to a source of inertia hedges. However, it should of course be noted that the inertia payments accruing to TNSPs might represent only a relatively small proportion of the inertia market, with the majority being earned by synchronous generators.

4.4 Proposed next steps

As noted in chapter 1, both the South Australian government and AGL submitted rule change requests relating to the management of high levels RoCoF and the potential for establishing procurement mechanisms for new services to address this. To date these rule changes have been progressed concurrently with the system strength rule change and in coordination with this review.

As outlined in chapter 3, draft determinations for the *Managing power system fault levels* rule change and the *Managing the rate of change of power system frequency* have been published alongside this report.

The Commission has 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 issues in the medium to longer term. While the Commission is of the view that the maintenance of power system security must be the priority, it is also conscious that a mechanism to provide market benefits would be an important complement to the TNSP-based mechanism that would deliver only an absolute minimum level of inertia for system security reasons.

Accordingly, the Commission has considered how the market benefits mechanism could be implemented as soon after the system security mechanism as possible. It has concluded that it would be possible to achieve this through the *Inertia ancillary service market* rule change proposed by AGL. While this rule change sought to implement arrangements based around long term contracting by AEMO, its objective was to provide a mechanism to reflect the value associated with inertia to providers of that service. As such, the Commission considers that it would be appropriate to implement a more preferable rule that seeks to achieve the same objective as part of that rule change.

Unlike the *Managing the rate of change of power system frequency* rule change, the Commission is not yet in a position to make a draft determination for the *Inertia ancillary service market* rule change. The potential mechanism has been identified since the directions paper, and requires further development and then consultation. While it is likely to be less complex to implement than a TNSP incentive scheme, there will still be a considerable amount of detail to work through in order to develop a draft rule.

In light of this, the Commission has made a decision under s.107 of the NEL to extend the period of time to make the draft determination until 7 November 2017. This will allow the necessary time for stakeholder consultation and to explore the issues necessary to further develop an efficient and effective mechanism.

5 Further development of frequency control ancillary services

Box 5.1 Summary of chapter

Over the course of the review, the Commission has investigated the use of frequency response services that respond more quickly than the existing FCAS contingency services as a complement to, and partial substitute for, inertia. The Commission has made recommendations around the provision of fast frequency response (FFR) services to TNSPs (to help meet the requirements being placed on them), through technical obligations and through their integration into FCAS markets.

This chapter provides more background to support the Commission's recommended approach to incorporating FFR into FCAS markets, as introduced in chapter 3.

- ***Recommendation 5:*** *Review the structure of FCAS markets, to consider:*
  - *any drivers for changes to the current arrangements, how to most appropriately incorporate FFR services, or alternatively enhancing incentives for FFR services, within the current six second contingency service; and*
  - *any longer-term options to facilitate co-optimisation between FCAS and inertia provision.*

The chapter also explains how this work is intended to be undertaken by the Commission as part of a *Frequency control frameworks review*, in cooperation with AEMO through its *Future System Services Program*.

5.1 Frequency control ancillary services markets in the NEM

Frequency control ancillary services (FCAS) are concerned with the timely injection of active power to arrest a change in frequency. That is, the ability to inject sufficient active power over a timeframe that maintains the technical performance of the power system, in this case, that satisfies the frequency operating standard (FOS).

In the NEM, FCAS is sourced from markets operating in parallel to the wholesale energy market, with the energy and FCAS markets being optimised simultaneously so that total costs are minimised.[73]

Currently the requirements for market FCAS are specified in clause 3.11.2(a) of the NER, although these are specified at a high level. Namely, the eight market ancillary services are:

73 For an introduction to FCAS markets, see: AEMO, *Guide to Ancillary Services in the National Electricity Market*, April 2015.

- fast raise and lower services
- slow raise and lower services
- delayed raise and lower services
- regulating raise and lower services.

An important design characteristic of FCAS services in the NEM is that participants in FCAS markets are paid for enabling the service in any dispatch interval in which they receive an enablement instruction. The price received is expressed in $/MW and is set on a basis consistent with the energy spot market (that is, where generator bids are sorted in order of price, with all participants receiving the same price consistent with the marginal generator offer).

Delivery of the service for which generators have been enabled will either be in response to an automatic generation control (AGC) signal sent by AEMO (for regulating FCAS), or automatically in response to a frequency disturbance measured by the generator (for contingency FCAS). Thus, generators receive an enablement payment irrespective of whether the service is required to be delivered. Where the service is required to be delivered, the generator also receives payment for any energy associated with the provision of the service.

5.1.1 Calculation of energy enabled

As noted above, the NER only provides high level descriptions of FCAS services and requires that AEMO prepares a market ancillary service specification (MASS) containing a detailed description of each kind of market ancillary service together with relevant performance parameters and requirements.[74]

Under the MASS, the current fastest service is the contingency six second service (termed fast raise and lower services in the NER, and sometimes referred to as R6/L6 services). This service is intended to arrest a rapid change in system frequency within six seconds of a frequency disturbance, and then provide an orderly transition to slow raise or lower services (which are sixty second services). The definition of this service is quite flexible in that generator participation simply requires some level of ability to respond to a frequency disturbance in a six second time frame and to sustain some level of that response for up to sixty seconds.

Specifically, the key defining characteristic of the six second service is that the calculation of the volume of service (MW) available from any generator is based on the actual energy estimated to be able to be injected over the measurement timeframe. That is, it is the sum of all the energy provided across the time frame of the service. The MASS defines this in terms of the lesser of twice the time average of the response between zero and six seconds and between six and sixty seconds.

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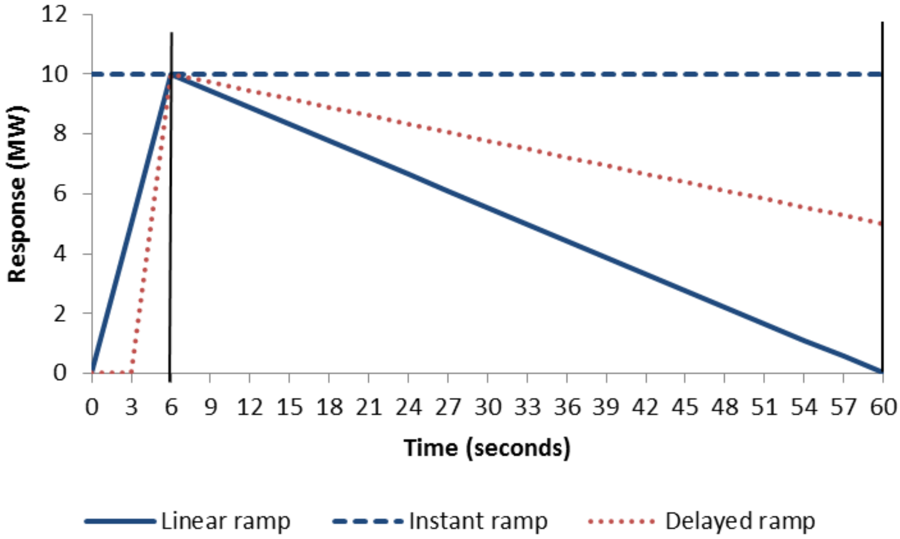
74 NER clause 3.11.2(b).

The impact of this measurement approach is illustrated in the following figure.

Figure 5.1 Six second FCAS MW profile



The above figure illustrates three possible energy profiles, namely linear, instant and delayed ramp profiles. In all instances, the maximum energy provided is 10MW within the six second timeframe. However, the key differences are:

- Under a linear ramp profile, the generator ramps up at a constant rate from time zero to six seconds and then ramps down steadily from six seconds until sixty seconds. Under the MASS this means that the generator will be paid for enabling 10 MW of power as the time average of the ramp up and ramp down are identical.

- Under the instant ramp profile, the generator provides a constant 10 MW over the entire sixty second time frame, meaning it is paid an enablement fee for 20MW of power.

- Finally, a delayed response ramp, where the generator takes three seconds to commence response, then follows a linear ramp profile to six seconds and then follows a linear ramp down to sixty seconds. This means the generator is only paid an enablement fee for 5MW. This results from the time average of energy provided from zero to six seconds being half that for the time average of energy provided from six seconds to sixty seconds, and therefore setting the MW target enabled.

The key point arising from the existing FCAS measurement approach outlined above is that it recognises the speed at which FCAS can be provided so that a generator that can provide a faster service will be credited with a higher MW enabled and therefore receive a higher payment than a slower response generator.

While this removes a possible distortion in terms of recognising the greater active power injection of fast response generators or devices, it does not necessarily recognise any enhanced system value that might be associated with faster response (for example, this is likely to be the case where there is an identified need for, and a limited supply of, faster FCAS and thus a scarcity premium could apply or where there is a higher opportunity cost associated with enabling a faster FCAS service compared to a slower service). This issue is addressed in section 5.3.

5.2 Determining FCAS requirements

In determining FCAS requirements it is necessary to understand how the system will respond to contingency events based on factors such as system load, contingency size and system inertia. This, in turn, will determine what is involved in providing timely injection of active power.

A key issue underpinning the need for FCAS services and their characteristics is that, as the size of system disturbances increases and as the amount of inertia decreases, the amount and speed of FCAS response needed to keep system frequency within the frequency operating standards (and avoid load or generator shedding) increases. The decline in system inertia with the increased penetration of non-synchronous generation is a key driver for introducing fast frequency response FCAS.

5.2.1 FCAS and FFR

AEMO has noted the technical challenges in managing frequency deviations in low inertia systems, and this issue is a key theme in its FPSS program.[75] The problem relates to the fact that supply-demand imbalances due to any disturbance will cause larger and more rapid frequency deviations in low inertia systems. This is already being seen in the NEM in South Australia.

As discussed earlier in this report, in the long term, the most efficient response to this issue is likely to be a combination of mechanisms to procure:

- inertia, to reduce the rate at which frequency changes in response to a disturbance; and
- FFR services, to rebalance supply and demand more quickly than existing FCAS services.

While there is no standardised definition of FFR (conceptually, it is simply a subcategory of FCAS) it can generally be thought of as a frequency support service operating in a time frame that is faster than historic standard-services. As noted above, the current fastest FCAS service is the contingency six second service.

To consider the potential benefits to system frequency control associated with more rapid active power injection in low inertia systems, AEMO, as part of the FPSS

75 AEMO, *Future Power System Program*, Progress Report, August 2016, p. 17.

program, commissioned GE to report on technology capabilities for fast frequency response. GE noted:[76]

> "There is a delicate interplay between FFR, PFR and inertia. The primary function of FFR is to arrest the frequency decline and "buy time" for PFR to act.[77] The amount of FFR needed and its efficacy is closely tied to the amount and quality of PFR available. For example, faster PFR will reduce the amount of FFR required at any given level of inertia; however at very low levels of inertia, conventional PFR (from synchronous generation) has limited ability to provide arresting energy fast enough."

In light of the GE report and its other work undertaken under the FPSS program, AEMO has reached a view that FFR is likely to become increasingly important in the future as system inertia levels continue to decrease:[78]

> "The use of FFR as a new, faster type of FCAS … is not essential immediately. However, AEMO's projections suggest that inertia levels will fall sufficiently over the coming decade or two such that it is no longer possible for typical synchronous governor responses (providing the R6/L6 services) to act rapidly enough to meet the Frequency Operating Standards (FOS). ... At this point, it will become extremely valuable to have a large, competitive pool of FFR providers available."

AEMO further notes the range of services that fall within the FFR category:

> "…FFR must be thought of as multiple categories of services, which can serve different roles and purposes."

This diversity of potential service definitions and uses for FFR creates a level of uncertainty around the preferred service and suggests the need for flexibility in developing any sourcing strategies. Concerns over this uncertainty have also been reflected in both this review and in AEMO's advice to ESCOSA's generator licensing requirements in South Australia in considering if and how to impose technical obligations on generators to have the capability to provide FFR (see next chapter).

The above discussion has highlighted that there is a degree of uncertainty over the extent of the need for FFR and the exact characteristics of any FFR that might be sourced at this time. These concerns suggest that it is appropriate to consider flexible options that may help support development of FFR-type services and that are likely to be able to be implemented relatively simply in the short term. One possible option is differential pricing for existing fast FCAS services.

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76 GE Energy Consulting, *Technology Capabilities for Fast Frequency Response*, Final Report, 9 March 2017, p. 6.

77 PFR is primary frequency response and is analogous to the current six contingency FCAS services in the NEM.

78 AEMO, submission to the interim report, p. 18.

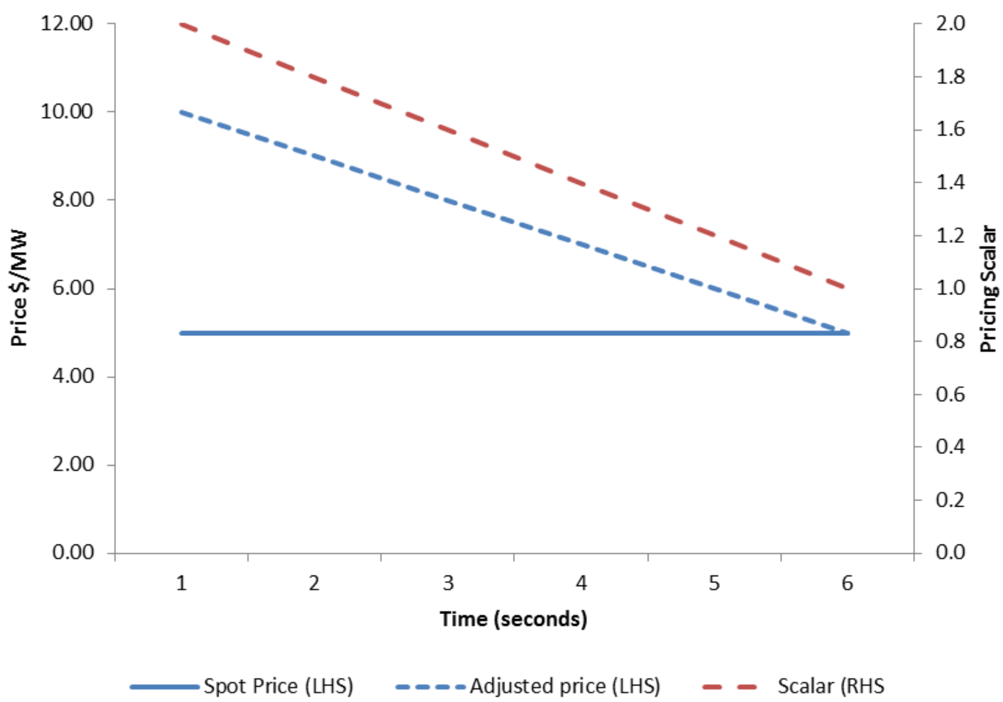
5.3 Differential pricing of six second FCAS services

As noted above, there may be circumstances where faster generator FCAS response is valued more highly than slower response. This is likely to be the case where there is an identified need for, and a limited supply of, faster FCAS and thus a scarcity premium could apply, or where there is a higher opportunity cost associated with enabling a faster FCAS service compared to a slower service.

This issue can be potentially addressed by development of specific FFR FCAS markets, thereby allowing the competitive bidding process to set the marginal price as discussed in the next section. However, in circumstances where the ideal FFR service characteristics are not clear or are likely to change over time, or where there may not be a sufficient pool of providers to guarantee competitive supply, development of specific FFR FCAS markets may not be the preferred option.

An alternative approach would be to consider introducing some form of differential pricing within the existing six second FCAS services. This could involve the application of a time weighted payment profile with each time slice receiving a different weighting, for example, a declining weighting with second "one" receiving X times second "six" and a linear adjustment across the intervening seconds. This approach is illustrated in the following figure.

Figure 5.2 Application of time weighted scalar to FCAS prices



A variation on the above approach would be to apply a scalar to individual generators registered to provide FCAS on the basis of their technical response capability. Such a generator weighting has been suggested as a possible option by AEMO, as follows:[79]

79 AEMO, submission to the interim report, p. 24.

> "If desired, scalars could be used to adjust the payments to each generator according to their capabilities. For example, faster response could result in higher payments."

AEMO noted that such an approach is applied in the PJM market in the US for dynamic regulation services and by EirGrid in Ireland for contingency FFR.

Adopting some form of weighted pricing approach or individual generator scalar is likely to require revisions to the rules as, under clause 3.11.1(b) of the NER, the prices for market ancillary services are to be determined using the dispatch algorithm. Where the rules allow for such arrangements, the details of the approach could be specified in the MASS.

On this basis, the Commission is of the view that consideration should be given to allowing for differential pricing within the current six second FCAS markets. It may be appropriate for AEMO in its future work program to further assess if and when such a development might be required, and to consider potential changes to the MASS and to its systems to implement such a change. The Ancillary Services Technical Advisory Group would allow for ongoing consultation with the relevant technical experts from industry. Any required changes to the rules could be developed by the Commission through the *Frequency control frameworks review*.

5.4 Longer term redevelopment of FCAS markets

As noted above, there are six contingency FCAS markets in the NEM designed to manage frequency control after a system disturbance. An increasingly important question is whether those markets remain relevant in terms of meeting the emerging needs of frequency control in the NEM.

In addressing this issue, relevant questions revolve around how many markets are required and what services should they cover. For example, should a new market be introduced for an FFR service and if so what should the service characteristics be?

Perhaps the simplest conceptual change to existing FCAS markets would be the introduction of raise and lower contingency services faster than the existing six second service. An example of such a service is the two second response (with eight second duration) service introduced in Ireland.[80]

Such a service is just one example of a possible FFR service definition - it is equally possible that a one second service or even a half second service could be introduced. There could also be differing duration requirements. It might even be argued, therefore, that multiple FFR markets should be introduced to capture different response elements that are valuable to the system.

Introducing an additional FFR market would increase the granularity of the FCAS markets and may provide better price signals for the value of fast response services.

80 DGA Consulting, *International Review of Frequency Control Adaptation*, 14 October 2016, p. 12.

However, the development of a new FCAS market or markets is likely to be complex and time consuming. In addition, as discussed in chapter 3, a number of stakeholders have expressed a view that existing arrangements for frequency control should be reviewed before additional services are designed and implemented.[81]

While, in chapter 3, the Commission noted that it agreed with these stakeholders that a re-examination of the existing arrangements should be undertaken as a priority, it considers that a wider program of work should then be conducted with a view to reconsidering and redeveloping robust FCAS markets for the long term.

Box 5.2 Issues for consideration in a review of FCAS markets

In comprehensively reviewing FCAS markets, it may be desirable in the first instance to reconsider the rationale for the markets that currently exist. This might involve alternative pricing approaches as discussed in the previous section or redefinition of the timeframes over which the differing services apply. For example, the current fast service might be redefined as a two second service with 10 second duration, the slow service as a 30 second service with two minutes duration etc. There are many alternative options that may better match the emerging needs for managing system frequency, especially in light of increasing levels of DER.

Currently, FCAS markets are co-optimised with the energy market. Going forward, FCAS may increasingly need to be optimised against dynamic system characteristics, such as the presence of inertia in each dispatch interval. The mechanisms for providing inertia recommended in this report are predominately targeted at addressing the risk associated with network separation, as this is where the issues currently lie. However, as levels of inertia decline into the future, a level of inertia will be required to manage contingencies across the NEM as a whole (e.g. loss of the largest generator). Consequently, any long term review of FCAS markets will need to consider how inertia provision can best be co-optimised against FCAS, with this potentially requiring the development of additional inertia services.

Finally, there will be a need to consider how the costs associated with any new services should be recovered. It may equally be appropriate to reconsider the charging arrangements associated with existing services, with some concerns being raised in this review that current charges for contingency FCAS do not provide efficient price signals.[82]

The Commission intends that the forthcoming *Frequency control frameworks review* will allow it to undertake this comprehensive review of the structure of existing FCAS markets. This would be supported in a technical capacity by work undertaken by AEMO.

81 CEC, submission to the directions paper, p. 3; Pacific Hydro, submission to the interim report, p. 1.

82 Intelligent Energy Systems, *A package of improvements for the NEM auction*, A report prepared by Intelligent Energy Systems for CS Energy, 18 April 2017, p. 15.

6 Technical standards

Box 6.1 Summary of chapter

Through the review, the Commission has explored the role of technical obligations in providing the capability for new services to be offered. The Commission's view is that, where this would not impose undue costs, it would act as a useful complement to the service procurement mechanisms discussed elsewhere in this report.

In the directions paper, the Commission set out, as part of its proposed package of immediate measures, a potential obligation on new non-synchronous generators to have the capability to provide FFR. Similarly, as part of its proposed response to system strength issues, it canvassed the potential introduction of an obligation for new inverter-based generation to be capable of operating at a given short circuit ratio.

The Commission has since given these issues further consideration and, with respect to frequency response capability, has modified its approach. However, it continues to consider that new technical obligations would be beneficial in both areas. Consequently, the Commission is making the following recommendations:

- ***Recommendation 2:*** *Consider requiring inverters and related items of plant within a connecting party's generating system to be capable of operating correctly down to specified system strength levels.*
- ***Recommendation 8:*** *Consider placing an obligation on all new entrant plant, whether synchronous or non-synchronous, to have fast active power control capabilities.*

The Commission notes that AEMO has announced that it intends to submit a rule change to the AEMC by July 2017 requesting revisions to the generator performance standards in the NER, consistent with advice it has provided regarding generator licence conditions in South Australia. This rule change will provide a mechanism for the further consideration, and potential implementation, of these recommendations.

6.1 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 penetration of this type of generation increases and the system strength decreases.

Modern inverters used for non-synchronous generation can often operate at lower short circuit ratios compared to older inverters and inverters with low technical performance. Inverter-based generation that can operate at a lower short circuit ratio would require less investment in the network to maintain the system strength at a sufficiently high level. Alternatively, if the system strength is low then inverter-based generation that cannot operate at low short circuit ratios may need to be constrained, depending on the mechanisms used to manage the performance of the generation at low short circuit ratios.

As outlined in chapter 3, the Commission is recommending that arrangements be introduced whereby connecting generators would have to agree to provide or fund the provision of services such that NSPs can continue to maintain agreed minimum levels of system strength where these would be affected by the new connection. This would place an incentive on new generators to minimise their impacts on system strength or to locate in an area where there is sufficient system strength.

In many parts of the NEM, the system strength is still relatively high and is likely to remain that way for several years, because there are currently baseload generating units operating there. Examples include the Hunter Valley, the Latrobe Valley and parts of Queensland. The installation of a new inverter-based generating system in one of these locations would not introduce a system strength issue, as the short circuit ratio would be relatively high.

In such circumstances, there may be little incentive on either the generator or the NSP to seek to minimise the effect of the connection on the local short circuit ratio. While this would not cause an immediate problem, it may increase costs for subsequent connections and/or consumers, as a potentially unnecessarily high short circuit ratio would have to be maintained over time. Consequently, the Commission considers that there would be merit in requiring inverters and related items of plant to be capable of operating at low minimum short circuit ratios, as this could significantly reduce future mitigation costs.

6.1.1 Where a minimum short circuit would be measured

It would seem most straightforward to specify a mandatory short circuit capability at the connection point of new generators, as this could be used to set a minimum level in connection negotiations between generators and NSPs. However, due to the varying nature of system strength across NSPs' networks and even within the networks which are part of the generating systems, the system strength at the terminals of sensitive generating system elements will always vary.

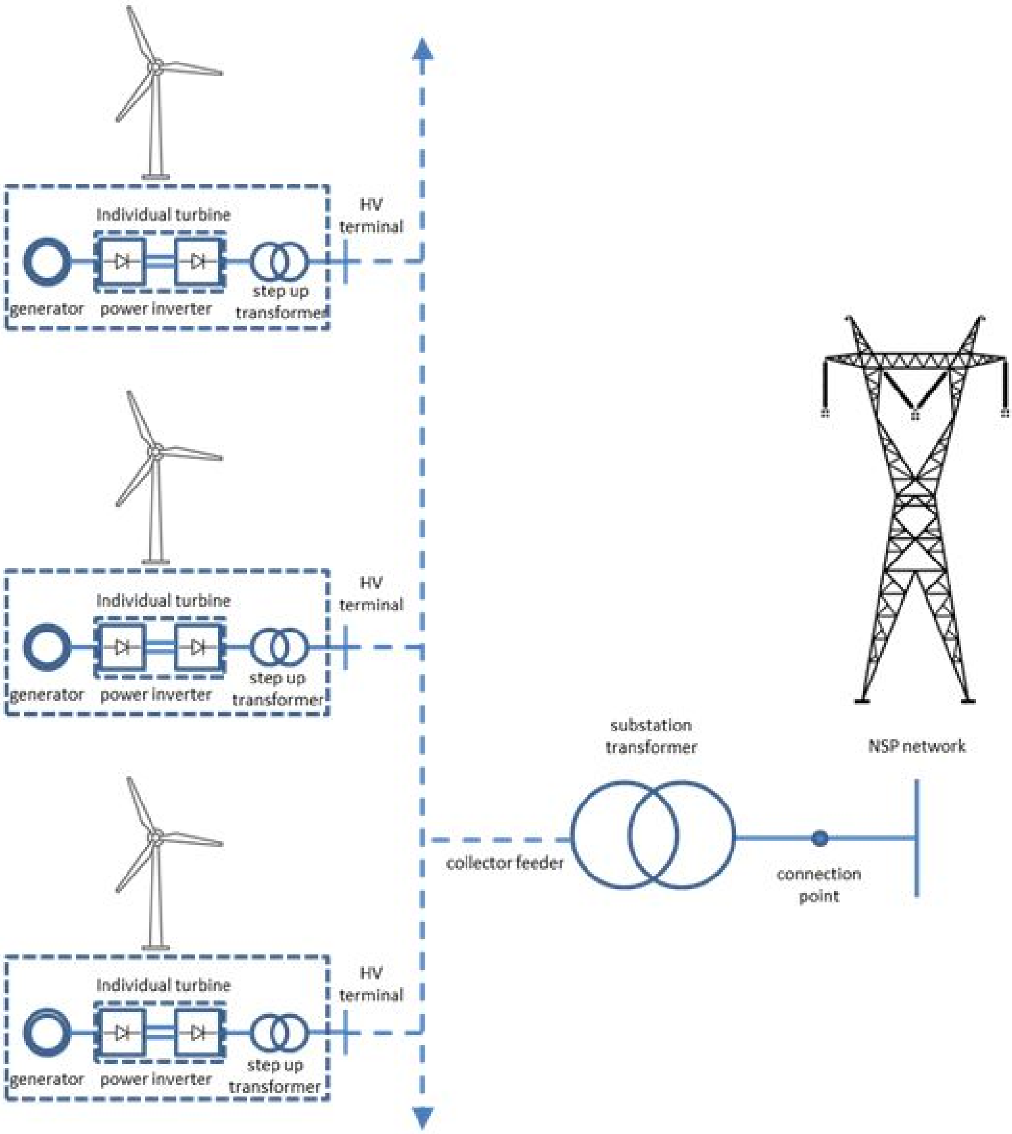
Figure 6.1 shows a connection diagram of a typical wind farm, which is representative of inverter-based generating systems. The system is made up of a number of wind turbines that consist of a turbine that drives an AC generator, a power inverter that converts the AC power from the generator to DC and then back to AC at the frequency of the power system, and a unit step up transformer that increases the voltage from that produced by the inverter to the collector feeder voltage. This is a high voltage (HV) compared to that produced by the inverter, and might typically be in the order of 33kV.

The individual wind turbines are interconnected through a collector feeder to the substation which forms the connection point with the NSP. The substation transformer increases the collector feeder voltage still higher, to the voltage of the NSP's network - perhaps 132kV or 275kV.

The individual wind turbines do not generally contribute to the system strength (fault level), so the system strength within the wind farm comes from the NSP network. This means that the system strength at the individual wind turbines will be less than that at the connection point due to the impedance of the collector feeder, with the system strength being the lowest at the wind turbine that is farthest from the substation.

As the inverter manufacturer would have knowledge and control over the specification of the inverter and the step up transformer, it would be best to specify the minimum short circuit ratio requirement of the inverters at the HV terminals of the step up transformer.

Figure 6.1 Inverter-based generation



6.1.2 AEMO advice on technical standards in South Australia

In its recent advice on recommended technical standards for generator licensing in South Australia, AEMO recommended that the Essential Services Commission of South Australia (ESCOSA) require susceptible items of plant within a connecting party's generating system to be capable of operating correctly down to both of the following levels at the HV terminals of each item of plant:[83]

- a minimum short circuit ratio of 1.5
- a minimum positive sequence X/R ratio of 2 (ratio of system inductive to resistive impedance).

AEMO noted that this recommendation appears the most practical way of minimising costs to future generators and, ultimately, customers and additionally suggested that there would be potential benefits to project developers, including:[84]

- Establishing a clear benchmark that all equipment manufacturers would need to meet in future would allow developers to utilise standard products rather than requiring bespoke designs to suit individual site conditions
- Reducing the overall system strength that the connecting party would need to negotiate from the NSP at the connection point would minimise the connecting party's need for additional system strength and any costs associated with procuring this additional support.
- There would be potential for a more efficient connection process due to a lower number of iterations associated with satisfying generator performance standard requirements under weak system requirements.

6.1.3 Implementation

In its advice to ESCOSA, AEMO noted that it intends to submit a rule change to the AEMC by July 2017 proposing revisions to the generator performance standards in the NER. AEMO expects that its recommendations to ESCOSA will form a key consideration in its upcoming rule change request, with the aim being for any new licence conditions imposed by ESCOSA to be transitional arrangements that are eventually able to be repealed, in whole or in part, following appropriate updates to the technical standards in the NER.[85]

The Commission consequently intends to use this rule change process to further examine, and potentially implement, the recommendation that new inverter-based

83 AEMO, *Recommended technical standards for generator licensing in South Australia*, Advice to ESCOSA, 31 March 2017, p. 42.

84 Ibid, p. 41.

85 Ibid, p. 16.

generation should be required to operate at a minimum short circuit ratio, and to consider what the level should be and how it should be measured.

6.2 Requirement for fast active power control facilities

Traditional frequency support services have been supplied by conventional synchronous generation such as steam or gas turbines with active speed governors and room to increase output. Critically, this form of response has a time delay measured in the seconds to tens of seconds range, as noted by GE:[86]

> "… it is important to note that it normally takes a second or so before any additional power is injected to the grid due to governor action. And that it normally takes several seconds, up to tens of seconds, before typical turbine-generators fully response [*sic*] to the frequency error."

Conventional generation technologies have the benefit of being synchronously or electromagnetically connected to the electricity system so that they can provide a seamless transition from an initial reliance on inertia to reduce the rate of change of frequency to a predictable injection of active power so that frequency is returned to the target level.

However, fast frequency services will necessarily be provided by non-traditional suppliers such as frequency responsive power electronic connected generation or load. By their nature, power electronic connected sources are non-synchronous and will exhibit a potentially wide range of performance characteristics.

For example, there are significant differences between the frequency control performance characteristics of wind farms and batteries. The response of these technologies to a frequency decline is as follows:

- FFR from wind relies on the temporary extraction of kinetic energy stored in the turbine rotor and drive train to deliver additional electrical power (this is often termed inertia-based FFR or IBFFR). However, this process causes the rotor to slow down and the energy extraction must then be repaid (as the rotor speeds back up to the optimum level) with the result that wind farm FFR is limited in duration (is energy limited) and involves a recovery phase during which total output is reduced.[87] A representative IBFFR profile would be similar to the Hydro-Québec requirement that wind farms larger than 10 MW must be able to provide a FFR response of greater than 6% of the name plate capacity within 1.5 seconds of a disturbance, with that response sustained for a minimum of nine seconds.[88]

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

87 Ibid, p. 41.

88 AECOM, *Feasibility of fast frequency response obligations of new generators*, 8 June 2017, Section 3.2.

- FFR from batteries is limited by the power and energy rating of the battery installation. However, batteries are effectively modular and completely scalable and, as such, can be designed to meet any specific requirements. However, it needs to be recognised that batteries are an energy storage solution and require an external source of electricity that can be stored. This means that they are energy constrained and also means batteries can, depending on their state of charge, act as either sources of load or generation. The response time of batteries to a frequency disturbance is generally extremely quick and is principally related to the detection and signalling time. GE has suggested the time to full activation after a trigger signal is received is in the order of 40 ms.[89]

It should be noted that the prevailing environmental conditions can have a very significant impact on any particular FFR source's potential FFR capability. For example, wind farm IBFFR capability declines rapidly as wind speed drops. Similarly, a battery that is being used to time shift solar PV generation may have little energy stored prior to the daily solar PV generation cycle and therefore limited ability to offer an extended duration FFR service at this time.

6.2.1 Defining a technology neutral requirement

The key issue with the differing performance characteristics of power electronic connected FFR sources is that it makes it very difficult to define a single FFR service and therefore to specify a single associated technology neutral technical obligation for generators or loads. Thus, it has been suggested that the best approach is to specify generic technical obligations that are not designed in terms of specific services but rather in terms of enablement of active power injection and control capabilities consistent with whatever technology is being adopted. This issue has been acknowledged by AEMO:[90]

> "AEMO cautions against immediately committing to prescriptive or long-term procurement options for FFR. … AEMO's recommendations in Chapter 6 regarding active power control capabilities are seen as broadly compatible with FFR provision from generators, without prescribing at this time specifically how these responses must be delivered."

AEMO goes on to note that the capability to provide an automatic active power response to frequency changes is necessary to provide contingency FCAS, or a governor-like response to changes in system frequency. As consequence, in its advice to ESCOSA on technical standards for generator licensing in South Australia, AEMO's recommendations included requirements that:[91]

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89 GE Energy Consulting, *Technology Capabilities for Fast Frequency Response – Final Report*, 9 March 2017, p. 4.

90 AEMO, *Recommended technical standards for generator licensing in South Australia*, 31 March 2017, p. 35.

91 Ibid, p. 46.

- Generating plant must be capable of automatically providing a proportional increase or decrease in active power output, in response to falling and rising power system frequency respectively.

- The steady state droop setting of this active power response must be adjustable in the range 2% to 10%.

- The frequency dead-band for this response must be adjustable in the range from 0 to +/- 1.0 Hz.

- Generating plant must be capable of sustaining a response to abnormal frequency conditions for at least 10 minutes, subject only to energy resource availability, or other plant technical or regulatory limits.

- An active power response to changing power system frequency must be provided with no delay, beyond that required for stable operation, or inherent in the plant controls, once frequency leaves the dead-band.

- Response to rising and falling frequency may be different, in both dead-band and droop settings, and in the response shape or characteristics. Different levels of droop may be applied for different levels of frequency change.

It should be noted that the term "active power control" is already used in the rules, which refers to the ability of a generating system to follow dispatch instructions issued electronically by AEMO.[92] This requires a generating system to be able to increase or decrease its active power generation within five minutes, in response to dispatch instructions, which is necessary for the operation of the spot market and to manage network constraints. The Commission is referring to the potential new requirement identified by AEMO as "fast active power control", which is similar but would require a much faster response - in the order of seconds - to provide support to the power system following a contingency event.

6.2.2 Implementation

The approach recommended by AEMO to ESCOSA may offer a framework that can be adopted within the NER. It is understood that this approach will be included in the technical standards rule change that is expected to be lodged. The Commission supports consideration of the adoption of fast active power control generator obligations through this process.

92 Schedule 5.2.5.14 of the NER.

Abbreviations

AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	automatic generation control
AS-TAG	Ancillary Services Technical Advisory Group
DER	distributed energy resource
DNSP	Distribution Network Service Provider
ESCOSA	Essential Services Commission of South Australia
FCAS	Frequency Control Ancillary Services
FFR	fast frequency response
FOS	Frequency Operating Standards
FPSS	Future Power System Security
IRSR	inter-regional settlement residue
MASS	market ancillary services specification
MVA	megavolt amps
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER or rules	National Electricity Rules
NSP	Network Service Provider
PSI TAG	Power System Issues Technology Advisory Group
SCR	short circuit ratio
SRA	settlements residue auction

SRAS	system restart ancillary services
STPIS	Service Target Performance Incentive Scheme
SVC	Static VAr compensator
TNSP	Transmission Network Service Provider

A Summary of issues raised in submissions

This appendix sets out the issues raised in the consultation on the directions paper to the *System security market frameworks review*. The AEMC's response to each issue is provided.

Stakeholder	Comment	Commission response
General comments		
ENA	The Commission's proposed approach should formalise roles and responsibilities for TNSPs and AEMO in regards to assessing system security in the NEM, with additional obligations for managing the impact on frequency and system strength caused by reduced levels of synchronous generation (p. 5).	Agreed. The Commission considers that the draft rules set out clear roles and paths of responsibility for AEMO and TNSPs.
TransGrid	The roles for TNSPs and AEMO need to be clearly defined and well understood (p. 2).	
Clean Energy Council	The present frequency control issues must be addressed as a critical priority for power system security and must be rectified before creating new market mechanisms (p. 2).	The Commission proposes to establish a *Frequency control frameworks review* which it intends to use as a means of assessing these issues. The introduction and development of any new market mechanisms will be undertaken in conjunction with the *Frequency control frameworks review*.
Clean Energy Council	The current design of the frequency regime prevents the use of primary governor control within the normal operating frequency band, and some market participants have been penalised for doing so. Participation by FFR providers will be inhibited while the FCAS regime deters this operating capability across all participants (p. 3).	The Commission intends that the forthcoming *Frequency control frameworks review* will allow it to examine issues associated with primary governor control and undertake a comprehensive review of the structure of the existing FCAS markets, including potential markets for FFR.

Stakeholder	Comment	Commission response
Origin Energy	The directions paper suggests that it may be difficult to develop clear criteria by which AEMO could assess competing disparate offers and that consumers would bear risks of over or under-procurement. This, however, is not a compelling reason to rule out AEMO from the procurement role given that these issues would also need to be overcome if the TNSPs were given responsibility for contracting. Irrespective of which party is responsible for procuring inertia and FFR, clear policies and procedures will need to be developed to help ensure an efficient level of contracting (p. 1).	The Commission considers the economic regulatory framework provides a framework for TNSP decision making by providing incentives to select the least-cost approach to meeting the obligation, with oversight and approval by the AER.
AER	The ROCOF challenge is one which is not unique to the NEM with a number of jurisdictions facing similar challenges. These are new and evolving complex engineering issues and careful consideration of all available evidence would be valuable before committing to a particular path (p. 2).	The Commission has drawn upon the work currently being undertaken by AEMO as part of its Future Power System Security Program. The AEMC has also considered the findings of investigations into the international experience of RoCoF, including reports from GE, DGA and AECOM.
CS Energy	In our opinion, the correct approach is to upgrade the power market auction to incentivise market participants, including new entrants, to keep the system reliable and secure. This should be superior to allocating the responsibility to regulated networks or prescribing by law, the provision of the service (p. 1).	One of the Commission's key principles is that competition and market signals generally lead to better outcomes than centralised planning, since they are more flexible to changing conditions and to consumers' needs. In this way, competitive market mechanisms are always the Commission's preferred approach. The Commission has therefore come to a view that a market-based mechanism is likely to be a more appropriate mechanism to use to deliver market benefits, and would have significant advantages in that wholesale market participants - rather than TNSPs - would continue to make generator commitment decisions.
	The Rules should look to allocate the responsibility for reliability and system security on Market Participants as this will reveal an efficient cost through competition. (p. 1).	
	With efficient marginal price signals, in the longer run, new and old technologies compete in the energy-only market without heavy regulation, specifications or compliance obligations. This will include consumers revealing their price elasticity, removing the missing money problem that occurs in energy only markets when consumer demand is rationed without reference to price (p. 1).	

Stakeholder	Comment	Commission response
ENA	The AEMC may also wish to consider how arrangements currently applying to AEMO could be applied to transmission networks when discharging similar obligations under the Rules. In many circumstances, the Rules afford AEMO necessary powers and/or reliefs from liability to ensure it is protected when meeting its obligations. Alternatively, the AEMC will need to consider how TNSPs price risk when determining the service response to meet obligations (p. 8).	The Commission considers that an absolute obligation on TNSPs to guarantee the availability of the required levels of inertia at all times is not practical. It may also result in excessive costs depending on the extent to which the TNSP needs to contract with a large number of inertia providers in order to confidently meet the obligation at all times. Therefore, under the draft rule for the *Managing the rate of change of power system frequency* rule change, the TNSP will be required to make a range and level of services available such that it is reasonably likely that the required levels of inertia are continuously available, taking into account planned outages and the risk of unplanned outages.
S&C Electric	Batteries connecting to a network will be treated as generation and so potentially trigger the “Causer pays” approach to reinforcement, when the battery may actually be connecting to resolve a constraint issue (p. 4).	The Commission considers that a comprehensive review of FCAS markets is likely to be desirable, including a review of the rationale for the markets that currently exist. See section 5.4 of the final report.
	We would be concerned if the current AEMC view that batteries should be treated as generation, resulted in a “Causer pays” approach in a situation where the batteries are being deployed to support the network (p. 4).	
Energy Queensland	The AEMC should give further consideration to the impacts of non-synchronous generation systems on distribution networks and their impact on the market as part of this review (p. 2).	The Commission anticipates giving these issues further consideration through its future work program, including through related projects such as the Distribution Market Model program.
ENA	A more specific role may need to be identified for the distribution network to address system security (p. 10).	
Fast frequency response		
S&C Electric	Throughout the directions paper there is a sense that FFR is a new and untried service. This is not correct and S&C Electric has delivered over 17 MW of batteries to deliver this service (p. 2).	The use of FFR as a contingency service is untested in the Australian context. However, the Commission considers that FFR services are likely to be effective in managing power system frequency and should

Stakeholder	Comment	Commission response
		be included as a possible means of meeting the secure operating level of inertia.
SA Government	Obligations for non-synchronous generators to provide FFR capability and to register to offer FFR is welcomed as a long term improvement to the management of the power system. This should be expanded to include raise and lower FCAS services that the technology is capable of contributing (p. 4).	The difficulty in defining specific FFR services has led the Commission to consider the adoption of a fast active power control generator obligation. The Commission intends to consider this through an anticipated rule change request from AEMO on technical standards.
SA Government	It would be more forward looking to allow any technology to compete to provide FFR, not just non-synchronous generation (p. 4).	The Commission is recommending that a fast active power control obligation is placed on all generators; both synchronous and non-synchronous. This recommendation will be considered for implementation in the rule change request to be submitted to the Commission by AEMO in July 2017. This recommendation is also consistent with the recommendation AEMO made in respect of the review of generator license conditions in South Australia.
SACOSS	The inclusion in the immediate package of requiring only non-synchronous generation to provide FFR capability seems inefficient: it should be all generation or none (p. 2).	
AEMO	AEMO does not recommend that a mandatory generator obligation for FFR capability is implemented at this time (p. 22).	
Energy Queensland	Consideration should be given to mechanisms to effectively share developments in FFR, both nationally and internationally; and innovation funding mechanisms for research and development to assist in accelerating the maturity of FFR technology (p. 4).	The Commission intends that the forthcoming *Frequency control frameworks review* will allow it to undertake a comprehensive review of the structure of existing FCAS markets. This will include the consideration of the longer term developments of frequency control markets.
Tesla	Welcome the fast frequency response contractual provisions included in the immediate package, which provide increased investment certainty for first-mover adopters of battery energy storage systems to deliver both FFR and synthetic inertia (p. 2).	The draft rule for the *Managing the rate of change of power system frequency* rule change request allows TNSPs to procure FFR services to substitute for some of the inertia required to operate a sub-network in a secure operating state. This substitution would need to be approved by AEMO. The Commission will be considering further implementation of FFR in the *Frequency control frameworks review* commencing July 2017.

Stakeholder	Comment	Commission response
	AEMO capability testing and drafting of FFR technical guidance should begin as soon as the draft rules are published. This will provide technology providers sufficient time to adjust systems and adapt interfaces as required (p. 2).	Under the draft rule for the *Managing the rate of change of power system frequency* rule change request, the TNSP will be able to enter into contractual arrangements with third party providers of FFR services, with approval from AEMO. This will be undertaken on a case-by-case basis in order to account for the varying characteristics of different technologies. Over time, greater experience with the implementation of these technologies will be developed.
	Tesla would like to see FFR Technical Guidance released as soon as is feasibly possible to avoid future concerns that the technology is emerging and ill-defined (p. 4).	The Commission will be considering these issues in the *Frequency control frameworks review* commencing July 2017.
	Tesla recommends that minimum contractual duration for FFR services would significantly advance first mover projects in the Australian market (p. 5).	The Commission has not proposed to place a minimum contract duration on FFR services. The Commission considers that these arrangements should remain at the discretion of the negotiating parties in order to maintain flexibility and efficiency in the provision of the services.
Australian Energy Council	The directions paper suggests that TNSPs should be used as a stop gap means of acquiring the necessary FFR. This conclusion overlooks the possibility that existing synchronous generators may also be able to provide FFR (p. 1,2).	While the Commission proposes that TNSPs would be able to contract for the FFR services in order to meet an agreed proportion of the required levels of inertia, this is unlikely to be relevant for synchronous generators that already provide inertia. A future market sourcing approach to FFR would allow all FFR providers to participate.
	The interaction between FFR services, FCAS and the existing energy market is such that these services cannot be contracted for in isolation. The proposed FFR market needs to be developed in consultation with market participants, and with consideration for the existing NEM design, a market which is designed to promote economic efficiency in dispatch and flexibility in adjusting to changing market conditions. (p. 3).	The existing FCAS spot market arrangements, while providing an effective means for efficiently enabling and dispatching these services, provide little in the way of revenue certainty that would be sufficient for significant investment to occur. The Commission intends to consider this issue as part of the *Frequency control frameworks review*.

Stakeholder	Comment	Commission response
RES	RES supports the proposal to apply ring fencing requirements to FFR devices (p. 3).	The AER is responsible for determining ring-fencing guidelines for transmission services. The AER has signalled its intention to revise the existing transmission ring-fencing guidelines. The Commission notes that this may impact the ability and incentives for TNSPs to compete in competitive markets for services in the NEM.
SACOME	If the funding avenues are too restrictive it may cause TNSPs to seek the cheapest option of FFR, which is load shedding. For SACOME members this can cause risks to personnel and plant, unacceptable interruptions to production, and material disruptions that endure for a prolonged period after the outage (p. 4).	Under the NER, the management of frequency through load shedding is not permitted for credible contingencies (although, under a notification by the jurisdictional system security coordinator for South Australia, the Frequency Operating Standards for South Australia following a separation event are such that frequency is assumed to be maintained within the standards through operation of the under-frequency load shedding scheme). Future FFR services may include controlled load reductions. However, these services would be provided through negotiation and payment with the service provider.
	The intention to establish an open market to procure FFR services is welcomed, though it will be critical to assess the varying levels of inertia set by AEMO against the market to determine what FFR services would become available (p. 5).	The Commission agrees that any future approach to sourcing inertia will need to be able to be co-optimised with a future potential market for FFR services.
SACOSS	If a market signal is desired in the long term (and SACOSS agree this is generally more desirable than not), then use of short duration, audited contracts for the short-term (say 1-4 year in tenure) for the provision of the required inertia or FFR services while the technical envelopes for the market are developed, would seem far more efficient than the current direction (p. 2).	Agreed. Under the draft rule for the *Managing the rate of change of power system frequency* rule change request, TNSPs will be able to enter into contracts with third-party providers of inertia and FFR services. The Commission intends to undertake further consideration of potential market sourcing approaches to inertia and FFR.

Stakeholder	Comment	Commission response
ENGIE	ENGIE does not support mandating that new non-synchronous generators be capable of providing FFR services. There are no rule obligations for connecting generators to have the capability to participate in the voluntary frequency control markets – rather these markets provide incentives for generators to have the ability to participate (p. 5).	The Commission is recommending that a fast active power control obligation is placed on all generators; both synchronous and non-synchronous. This recommendation will be considered for implementation in the rule change request to be submitted to the Commission by AEMO in July 2017. This recommendation is also consistent with the recommendation AEMO made in respect of the review of generator license conditions in South Australia. The Commission is making this recommendation as it is considered important for generators to have the capability to provide fast active power control when developing a project as opposed to retrofitting the capability.
Origin Energy	The introduction of a requirement for new non-synchronous generation to have FFR capability could be considered if it is found to not be overly onerous for these plant (p. 2).	
	We question an unlimited contract length for FFR services, especially if the AEMC intends to transition to a market based approach after 3 years. A limit on contract length would not unduly undermine investment certainty and will provide greater clarity around the planned transition (p. 2).	The Commission has not proposed to place a maximum contract duration on FFR services. The Commission considers that these arrangements should remain at the discretion of the negotiating parties in order to maintain flexibility and efficiency in the provision of the services.
AER	Future studies should consider the role of existing technologies, such as battery storage, in further detail to understand how they could deliver services to manage ROCOF. They should also consider how these technologies will evolve over time and what the role of distributed energy services might be. Most importantly they will need to consider how these technologies will interact with the existing and new market mechanism and what barriers exist to their deployment across the NEM (p. 2).	The Commission proposes to undertake further investigations into potential mechanisms for the provision of FFR services. An essential component of this will be an understanding of the nature of the technology providers.
	The fast-frequency market can relatively easily be appended to the existing frequency control ancillary services (FCAS) markets and dispatch of these services can be co-optimised with the wholesale market (p. 2).	Through the *Frequency control frameworks review*, the Commission will explore ways of integrating FFR into existing FCAS markets. The Commission also agrees that any future approach to sourcing FFR will need to be able to be co-optimised with the wholesale market.

Stakeholder	Comment	Commission response
AEMO	AEMO proposes that the transitional FFR mechanism should achieve two objectives: Ensure a large, competitive pool of FFR providers is available in future, when it will offer substantial value to consumers and allow AEMO and other market participants to gain practical experience with a wide range of types of FFR providers, ensuring these services can be used effectively and with high confidence when they are ultimately required (p. 19).	Under the draft rule for the *Managing the rate of change of power system frequency* rule change request, the ability for the TNSP to contract for the provision of alternative services should allow market participants and AEMO to gain practical experience with different types of FFR. The Commission is also investigating additional future measures for FFR services.
AEMO	Given the novelty of large low inertia systems, and the global inexperience with the use of FFR in general, AEMO believes it will take several years before there is sufficient operational certainty to approve any substitutions with a sufficient degree of certainty. Therefore, this approach would likely lead to very little investment in FFR in the near term. This will miss important opportunities to include this capability (at a small incremental cost) with new participants entering the market (p. 21).	The Commission will be considering these issues in the *Frequency control frameworks review* commencing July 2017.
	Variable FFR providers (such as wind and PV) may not be able to easily contract with TNSPs as a substitute for inertia, given their variable availability. As a rule of thumb, wind inertia-based FFR can typically provide around 10% of the wind farm operating level in FFR. This means that the FFR service will only be available when the wind farm is operating at higher levels, which may not correlate exactly with the periods when there is an inertia shortfall. Therefore, the TNSP is more likely to prefer FFR solutions with firm availability, such as storage technologies. Wind and PV provide some of the lowest cost options for delivery of FFR in future, and will be able to deliver a useful service in many periods. The intention of the initial (transitional) mechanism is to develop a large pool of FFR capability, and to allow AEMO and the market to gain experience with these technologies. This is not likely to be achieved by the mechanism proposed by the AEMC, since wind and PV technologies are not likely to be included. (p. 22)	The Commission acknowledges that when substituting inertia for FFR, TNSPs may prefer FFR with firm availability. Under the draft rule, it would be the decision of the TNSP and AEMO to determine whether FFR is an appropriate substitute for a level of inertia. The Commission will be considering these issues in the *Frequency control frameworks review* commencing July 2017.

Stakeholder	Comment	Commission response
Inertia procurement		
SA Government	In determining a minimum operating level of inertia, a number of scenarios related to protected events would also be modelled by AEMO. This presents further complication on setting a required level of inertia should AEMO take some ex ante actions (FCAS and/or constraining dispatch) or the EFCS scheme associated with that event triggering ex-post load or generation shedding (p. 3).	The capabilities of existing frequency response services will be taken into consideration by AEMO when determining the minimum required levels of inertia.
	It does not seem the network support and control ancillary service NSCAS framework is sufficient to cover the provision of inertia. The AEMC should consider if the rules need to be changed for TNSPs to be able to provide a prescribed operating level of inertia (p. 5).	The Commission considers that obligating TNSPs to provide a required level of inertia provides a more immediate solution then pursuing a similar outcome through the existing NSCAS framework.
	The AEMC needs to consider what level of flexibility is appropriate for AEMO in determining the minimum operating level of inertia (p. 5).	The Commission has proposed that the methodology for determining minimum required levels of inertia would be prescriptive and would be based on maintaining the islanded sub-network in either a satisfactory operating state or a secure operating state.
	If AEMO determines the required operating level of inertia in a region, the TNSP should have freedom to locate where the inertia is to be supplied to maximising the synergy between inertia system strength (p. 6).	Agreed. The TNSP should be best placed to coordinate the location of services to optimise inertia and system strength requirements.
	If the issues with contracting for inertia from synchronous machines cannot be resolved, the Division considers that the most likely and straightforward solution is to limit inertia provision to non-generating sources in the interim (p. 7).	The draft rule enables the TNSP to meet the obligation through either contracting with third-party providers of inertia or physically constructing the required assets. The Commission proposes that this decision should be based on a least-cost assessment.

Stakeholder	Comment	Commission response
Reach Solar	The inertia needed on a real time basis should be quantified by AEMO (p. 3).	AEMO will not be obliged to provide the full secure operating level of inertia to the system if it does not consider it necessary to maintain the islanded sub-network in a secure operating state. The Commission considers that AEMO is best placed to be able to determine the optimal amount of inertia to be provided based on changing system conditions, including maximum contingency size and the tolerance of the system to RoCoF.
Energy Queensland	Where a disparity exists between the type and volume of generation it will become increasingly important to localise the inertia requirements beyond a single state level. Mechanisms to localise the inertia requirements in such instances will be critical to maintain the stability of the system (p. 4).	AEMO will be required to determine the sub-networks for the purposes of procuring the required levels of inertia. It will be at AEMO's discretion to adjust the boundaries of any inertia sub-networks or establish any new inertia sub-networks.
Tesla	Tesla would like to see an inertia market that is open to accepting synthetic inertia where technical capabilities meet AEMO defined requirements (p. 3).	Under the draft rule, the TNSP will be able to undertake activities in addition to the procurement of inertia to meet its obligation to procure the secure operating level of inertia. Any additional activities undertaken by the TNSP to meet the obligation will require approval from AEMO.
ENA	The Commission should also consider how the prescribed process for determining the required operating level of inertia relates to: the timing of the TAPR process; the establishment of the obligation; the Regulatory Investment Test for Transmission (RIT-T) process; the final procurement of the service (p. 6).	The Commission has included transitional as well as enduring amendments with the draft rule to account for the timing implications of implementing the obligation on TNSPs.
SEA Gas	SEA Gas shares Engie's concerns noted in the Directions Paper and, aside from resolving despatch / merit order complexities, further queries how it is intended that the TNSP will factor into its decisions the impact that incremental energy contributed by synchronous generators dispatched for the purpose of procuring additional inertia will have on market price (p. 1).	The TNSP will negotiate commercial terms of agreements with generators providing inertia. The contracted generators will be constrained on by AEMO and their minimum loading level will not be factored into the calculation of the dispatch price.

Stakeholder	Comment	Commission response
Hydro Tasmania	AEMO is well placed to determine required inertia levels for mainland and Tasmanian regions. The process to determine inertia should be transparent and provide an opportunity for market participants to be consulted where appropriate (p. 1).	The development of the process to determine the required inertia levels will follow the Rules consultation procedures. AEMO will review the required levels of inertia no more frequently than once every 12 months.
SACOME	The level should be assessed regularly by AEMO and open to review by expert third parties to ensure that it is set at an appropriate level and has taken all factors into account for a respective market in the NEM (p. 3).	
Clean Energy Council	Inertial contribution from these units to meet a minimum inertia level requires greater confidence in performance, given the fundamental nature of system security. Therefore, it is unacceptable that generating units within unknown or undeclared RoCoF withstand capability might contribute to firm system security inertia limits (p. 5).	Under the draft rule, the TNSP will be required to provide information to AEMO on the final form of network support agreements that it enters into with generators for the provision of inertia. The information will include details of the RoCoF withstand capability of the contracted generator.
	The Commission and National Electricity Rules must be clear that only generating units with clearly stated and known RoCoF performance standards may participate in the provision of inertia services (p. 6).	
ENGIE	ENGIE suggests that the management of power system frequency and inertia involve real time consideration of generation and loads across the entire power system and that it is well beyond the scope of the TNSP to be able to take into account all the relevant variables to be able to manage these concepts (p. 3).	The Commission considers that one of the issues with a TNSP incentive scheme for inertia is that it would require the TNSPs to monitor and participate in the wholesale market in a much more involved way. Its success would rely on TNSPs making real time decisions about committing generation and scheduling inertia to alleviate constraints, a role they have not previously engaged in. A potential market sourcing approach to the provision of inertia would ideally allow for all providers of inertia to be making commitment decisions based on prevailing market conditions.

Stakeholder	Comment	Commission response
AER	We think there would be little value in establishing an inertia specific incentive similar to the Service Targets Performance Incentive Scheme (p. 2).	In the directions paper, the Commission outlined the possibility that a TNSP incentive framework could be developed to guide the procurement and dispatch of, and investment in, inertia to provide market benefits. However, there are some difficulties in developing and implementing a TNSP incentive framework. Since the directions paper, the Commission has identified and developed a market sourcing approach as a potential alternative option to guide the provision of additional inertia for market benefit.
	If a TNSP proposed an augmentation, or a contingent project, to address a ROCOF need today we would consider it as part of their revenue proposal. For example, the TNSP could identify an obligation which drives the need, such as the South Australian 3 Hertz/second ROCOF requirement (p. 3).	The establishment of potential RoCoF constraints in the future may drive the development of TNSP projects under the RIT-T framework to alleviate those constraints.
AEMO	AEMO supports implementing an approach that would encourage the procurement of inertia for market benefits beyond any minimum level required for the resilient operation of the grid (p. 3).	Agreed. The Commission considers 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 additional inertia above the minimum required level and that this would further contribute to the NEO.
	AEMO suggests that there is no single fixed level of inertia which can accurately capture the inertia requirements of the grid or align with the options available to a TNSP (p. 5).	Agreed. In practice, the level of inertia required to limit RoCoF and maintain the secure operation of the power system varies with changing system conditions. There is no one level of inertia that can be considered efficient under all circumstances.
	AEMO does not consider it reasonable to require a TNSP to maintain a fixed level of inertia available at all times. This would result in an oversupply of inertia in many periods, and would be an overly onerous requirement on both the TNSP and potential providers. Requiring a constant level of inertia would also deliver inefficient investment, and potential limit participation to only baseload inertia providers (p. 5).	Agreed. The minimum required levels of inertia will only be required to be provided at times determined by AEMO for reasons of system security. The Commission is further investigating the variable provision of additional inertia for market benefit.

Stakeholder	Comment	Commission response
	AEMO recommends that the responsibility for dispatching inertia sit with AEMO. This is similar to other grid services procured by the TNSP, such as NSAs for reactive power. Once procured by the TNSP, AEMO should be advised of the contracts, and develop procedures for committing inertia if it was required (p. 8).	Agreed. Under the draft rule, AEMO will provide instructions for the provision of inertia in accordance with a schedule prepared by the TNSP.
	AEMO suggests that restrictions be placed on the inertia procurement contracts, determined in consultation with AEMO. The TNSP should consider how contracts could be dispatched operationally, and the interaction of inertia providers and the energy market (p. 8).	The TNSP will be required to provide information to AEMO on the final form of network support agreements that it enters into with generators for the provision of inertia, including periods of notice and response times, and any other restrictions.
ENA	Understanding the consequences of failing to provide the required operating level of inertia will be an important consideration for TNSPs in managing associated risks and costs in developing contractual arrangements to meet obligations (p. 7).	The Commission considers that an absolute obligation on TNSPs to guarantee the availability of the required levels of inertia at all times is not practical. Under the draft rule, the TNSP will be required to make a range and level of services available such that it is reasonably likely that the required levels of inertia are continuously available, taking into account planned outages and the risk of unplanned outages.
	In instances where TNSPs may not be able to procure the necessary operating level of inertia, or alternatively where the cost of procurement appears to be excessive due to the limited market, some form of transitional arrangement may be necessary (p. 8).	
Interaction between inertia and fast frequency response		
AER	We do not believe that TNSPs procuring ROCOF services should be required once a market in fast-frequency is established (p. 2).	In the current power system there is a minimum threshold level of inertia which must be provided in order to maintain at least a satisfactory operating state. FFR services cannot be substituted for this minimum level of inertia.
AEMO	Although FFR and inertia are closely related services, and the quantities required for each will be inter-dependent, they should be considered as two distinct services, with different roles and purposes (p. 19).	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 or reduces consumption to arrest the

Stakeholder	Comment	Commission response
		frequency change and revert the frequency back towards normal operating levels. An increase in the size or speed of frequency control services should reduce the amount of inertia needed to maintain the secure operation of the power system. However, the extent to which increased levels of frequency response services can be used as an alternative to inertia is limited. Frequency control services would not be able to substitute for the minimum threshold level of inertia, which is the minimum amount of inertia needed to operate the inertia sub-network in a satisfactory operating state when islanded.
ATCO	Concerned with the apparent bias towards central planning and investment, evidenced by the proposal to rely on TNSPs to manage the procurement of inertia and FFR (p. 2).	The Commission considers that the potential costs associated with this risk are relatively low given that the TNSPs are only required to make the absolute minimum levels of inertia available. The Commission is further investigating the variable provision of additional inertia for market benefit.
	It is likely that this approach will create perverse incentives to encourage investment in potentially redundant infrastructure (p. 2).	
	A more effective mechanism would be open markets for system frequency and inertia as contestable ancillary services (p. 3).	
ENA	Clarification should be provided as to whether the proposed additional obligations on TNSPs are intended to apply to all TNSPs regardless of whether they are the Jurisdictional Planning Body for a particular jurisdiction (p. 5).	The obligation will be placed on the TNSP that has the transmission planning responsibility in each electrical sub-network.
RES	The development of a TNSP incentive framework should be structured to support the procurement of solutions that manage frequency on a least cost basis, rather than incentivising increased volumes of particular technologies (p. 4).	The Commission considers that a market sourcing approach for the provision of inertia would likely be superior to a TNSP incentive framework in that it would better be able to be co-optimised with a market sourcing approach for the provision of other frequency control services, including a potential future FFR service.

Stakeholder	Comment	Commission response
System strength		
SEA Gas	SEA Gas considers it critical that potential improvements to system strength are an integral part of the incentive framework to be developed in relation to any additional inertia provided by the TNSP above the required operating level (p. 1).	When investing 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 levels of inertia needed to maintain system security. Meeting the required levels of inertia and minimum required levels of system strength in a coordinated manner should be an inherent part of the TNSP's planning process.
Clean Energy Council	It will be critical that the NER provides ample opportunity for the connecting party to manage this risk and cost, rather than expecting the local TNSP to contract for the provision of these services in all cases (p. 6).	The draft rule on the *Managing power system fault levels* rule change request allows for the connecting party to propose a system strength remediation scheme. This provides the connecting party with flexibility in addressing the impacts on its connection to the network.
S&C Electric	S&C Electric would support an approach that allowed generators to meet their obligation by placing equipment on their site (p. 3).	
	The ability to "free-ride" is also a concern (page 78), with the last connecting generator potentially bearing more of the cost, than is merited by its single impact. All parties connected to that part of the system have contributed to the issue and have a role in the costs and the benefits (pp. 3-4).	Under the draft rule, connecting parties would only be required to remediate the impacts associated with their connection.
	A fairer approach to the distribution of costs associated with maintaining system strength, rather than "causer pays" should be developed. "Causer pays" is likely to ensure that the deemed "causer" that triggers reinforcement (or the requirement to fund network support) is unlikely to connect and seek an alternative connection location that doesn't have the additional cost. This will mean that the reduced strength on that part of the network will not be addressed by a future connectee nor the NSP (p. 4).	Generators would be able to either connect and fund the associated costs of remediating system strength impacts or relocate to an alternate location. The system strength in that part of the network would be addressed either as a future generator connects, or when an NSP is maintaining system strength for the purposes of network protection systems or managing network voltages.

Stakeholder	Comment	Commission response
Energy Queensland	Energy Queensland would recommend that as soon as a generator makes its pending retirement known to the market, the resultant short circuit ratio should be used for managing new connection applications (p. 5).	The NSP would need to consider this when meeting its obligation.
	One of these changes is real-time management of system strength by AEMO (section 5.5.3) which could involve constraining the output of an affected generating system. Such a constraint may be possible for semi-scheduled and scheduled generators but this approach may not be effective where the generator is non-scheduled or exempt and AEMO lacks visibility and control (p. 6).	The Commission notes this issue. However, AEMO would be responsible for maintaining system strength on an ongoing basis and would need to undertake action necessary to maintain system security.
Hydro Tasmania	Care needs to be taken so that investments made now do not subsequently lock out investment in emerging technologies or market solutions in the future that provide a more cost effective solution for customers (p. 1).	NSPs will be obliged to undertake actions necessary to maintain system strength. Under network regulatory arrangements, NSPs have incentives to minimise costs by either undertaking investments or contracting for operational actions.
RES	By introducing short circuit ratio requirements, synchronous condensers are favoured over alternative technology (p. 8).	
Hydro Tasmania	System strength or inertia could be addressed by adopting a network solution, which may also provide energy services. TNSPs are however limited in their ability to provide energy services in the market. The regulatory framework will therefore need to be adapted to ensure that barriers to provide least cost solutions are adequately addressed (p. 2).	The Commission will be considering options for procuring inertia for market benefits in greater detail. The Commission's considerations will be presented in the *Inertia ancillary service market* draft determination, due to be published 7 November 2017.
	As an interim measure, Hydro Tasmania supports adapting the existing Network Support and Control Ancillary Services framework to procure system security services as well as market benefits and believes that this framework should be considered further by the AEMC (p. 2).	

Stakeholder	Comment	Commission response
RES	RES Australia opposes the proposal to place an obligation on NSPs to maintain the short circuit ratio at each generating system's connection point. RES is concerned that the proposal will result in unnecessary costs for new generators and ultimately consumers (p. 1).	The Commission considers it is crucial that system security is maintained. In order for this to be achieved, the Commission considers that system strength for existing generators should be maintained by NSPs to a level that allows them to meet their performance standards. The Commission is not convinced that without this obligation on NSPs, the security of the system would be maintained. While the Commission notes that AEMO will have to maintain system security on an ongoing basis, this is likely to be inefficient and would likely be given effect through operational actions instead of investment in equipment where that may be the most efficient solution.
	Any new rule that requires the explicit maintenance or increase of fault levels is likely to introduce unnecessary costs to consumers either through increased generation or network costs. (p. 4).	
	The normalisation of system strength through the use of the SCR metric can introduce some significant issues. For example, if a number of generators with separate connection points are connected in the same part of the transmission network, a complicated SCR rationing approach may be required. RES does not support the explicit use of the SCR metric within the NER (p. 4).	The draft rule outlines a requirement for AEMO to determine a guideline for calculating short circuit ratios, including for circumstances where there is the need to ration system strength between multiple generators.
	RES Australia suggested that the Commission explore the potential for NSPs to re-negotiate lower performance standards with existing generators with the objective of maintaining system security whilst minimising total costs (p. 4).	The draft rule provides for the option of the NSP providing system strength works including negotiating with an existing generator to lower its registered short circuit ratio.
	RES does not support the view that there is a need to allocate responsibility to one or more parties to maintain SCR for existing generator connections. Introducing the requirement to maintain SCR for generator connections will result in unnecessary expenditure. The key issue is the ability of generators to continue to meet their performance standards. The rules should recognise this issue and not use SCR as a simplified proxy (p. 5).	As discussed in chapter 3 of the *Managing power system fault levels* draft determination, there are issues that arise if existing generators were made responsible for maintaining system strength to a level that would allow them to meet their performance standards.

Stakeholder	Comment	Commission response
	RES also notes that there may be a significant level of uncertainty and ambiguity if a large synchronous generator commits to retirement when a proposed asynchronous generator is undergoing the connection application process (p. 7).	The NSP is responsible for maintaining the short circuit ratio to existing generators when a large synchronous generator retires. New generators only need to do no harm in respect of the equipment they are connecting.
	It will be essential that the NER provide sufficient opportunities for connecting generators to manage their own risks and costs, rather than allowing NSPs to select the preferred solution and pass through the associated costs (p. 7).	The NSPs need to coordinate activities related to system strength with their other activities. The draft rule provides connecting parties with the option of being able to propose a system strength remediation scheme to the relevant NSP. A system strength remediation scheme would allow connecting generators to manage their own risks and costs if accepted by the NSP and AEMO. System strength remediation schemes are discussed in more detail in chapter 4 of the *Managing power system fault levels* draft determination.
	The registered SCR should be based on the technical ability of the generator to meet its performance standard, rather than the assumed SCR at the time of connection. (p. 7).	The Commission agrees. Under the draft rule, the registered short circuit ratio for existing generators would be based on technical capability.
	There is typically a mismatch in design life between generating assets and network assets. For example, a connecting generator with a design life of 25 years should not be required to fund a network asset with a design life of 45 years (p. 7).	This would need to be negotiated between the NSP and the generator. As discussed above, generators would have the option of proposing a system strength remediation scheme as an alternative to being provided system strength connection works by the NSP.
	The directions paper has not outlined a cost sharing methodology for short circuit ratio augmentations (p. 8).	Chapters 3 and 4 of the draft determination for the *Managing power system fault levels* rule change request discuss cost recovery for existing and new generating systems.
Clean Energy Council	It will be critical that the NER provide ample opportunity for the connecting party to manage this risk and cost, rather than expecting the local TNSP to contract for the provision of these services in all cases (p. 6).	The draft rule for the *Managing power system fault levels* rule change request allows for the connecting party to propose a system strength remediation scheme. This provides the connecting party with flexibility in addressing the impacts of its connection to the network.

Stakeholder	Comment	Commission response
	The NER already carry an obligation in cl. 5.3.5(d) that prevents a connecting generator from doing harm to the performance standards of an existing generator. It is unclear why an additional system strength obligation is required to be considered (p. 6).	The Commission considers that the draft rule for the *Managing power system fault levels* rule change request clearly allocates responsibility for maintaining system strength. Additionally, the draft rule makes clear that connecting parties would be required to pay the costs associated with the impact of their connection on existing generators' registered short circuit ratios.
	System strength obligations should be limited to the transmission network. They can already be managed locally within the distribution network generator connections arrangements and procedures (cl. 5.3.5(d)). Given there is thousands of kilometres of weak distribution network in the NEM blanket minimum standards, if applied to distribution networks would have major investment ramifications for DNSPs (consumers) that have not been justified by this review (p. 7).	The Commission considers that the same system security risks of large generator failures present in the transmission network extend into the distribution network. DNSPs would be required to maintain system strength at a sufficient level for connected generator in addition to current obligations to maintain effective network protection systems and manage network voltages. The Commission notes that the most efficient solution to low system strength in distribution networks may be implemented in the transmission network. This option is provided for under the joint planning obligations in the NER.
	The power quality (harmonics and flicker) allocation processes already set a precedent that should be replicated for system strength (p. 7).	The process for allocating power quality is contingent on a determined level of power quality that can be allocated to connected parties. The Commission acknowledges that while this approach may be applicable when a new generator connects to a part of the network with sufficient system strength, it does not provide for circumstances such as the retirement of a synchronous generator reducing the available system strength.
	As the TNSP may be the provider of the system strength through meeting its inertia requirements, the NER should be clear that this would be a negotiated service provided under the negotiating guidelines and with scope for the use of the independent engineer, as set out by the Transmission connections and planning arrangements rule change (p. 7).	Under the draft rule for the *Managing power system fault levels* rule change request, if a TNSP is providing system strength connection works to a connecting generator, this would be provided as a negotiated transmission service. As such, the connecting party and the TNSP would be able to call for independent technical advice from an independent engineer.

Stakeholder	Comment	Commission response
	The Commission's proposal to consider applying minimum short circuit ratio standards to inverter-based generation omits the stability limits of synchronous plant. If a standard is to be applied, it should be technology neutral and apply to all generating equipment (p. 7).	The Commission has recommended that such a requirement be considered further for implementation through a rule change request expected to be received from AEMO.
AEMO	There may be merit in considering what would drive acceptable minimum levels of short circuit ratio, and whether the NER should provide guidance or standards in relation to that (p. 27).	The draft rule for the *Managing power system fault levels* rule change request will introduce a requirement for AEMO to develop short circuit ratio calculation guidelines. These guidelines would provide guidance to connecting parties and NSPs on how to determine short circuit ratios.
	It would be important to consider a broad range of factors when considering whether inverter based generation should be able to operate at a certain short circuit ratio. This should cover the possibility of: • Some generating systems might have many generating units that are geographically and electrically remote from the connection point while other generating systems might have few generating units close to the connection point. • Some central network solutions might have lower overall cost than multiple solutions at multiple individual generating units. • Some network locations might have high system strength so the improved generating unit performance might not be necessary (p. 27).	The draft rule for the *Managing power system fault levels* rule change request does not require generators to be able to operate at a certain short circuit ratio. The draft rule includes a requirement for AEMO to develop short circuit ratio calculation guidelines to maintain an effective level of system strength. These guidelines should: • include the method for calculating the short circuit ratio from a given set of fault levels within the network • provide guidance to the NSP as to the different network conditions and dispatch patterns that should be examined by the NSP when determining the fault levels within the network

Stakeholder	Comment	Commission response
Transition between immediate and subsequent packages		
ENA	We expect, as part of further consultation, the AEMC will provide further information on how TNSPs, AEMO and other market participants transition from the immediate package to the subsequent package (p. 11).	The draft determination for the *Managing the rate of change of power system frequency* rule change request outlines an initial set of obligations on TNSPs to procure a minimum level of inertia. The Commission will be considering options for procuring inertia for market benefits in greater detail. The Commissions considerations will be presented in the *Inertia ancillary service market* draft determination, due to be published 7 November 2017. This will consider any transition in obligations placed on TNSPs.
	The Commission should consider the need for sufficient notice in relation to adjustments to transitional frameworks from one regime to the other (p. 12).	
TransGrid	The transition from the immediate package to the subsequent package could be further clarified. It is not clear how the market sourcing approach in the subsequent package would interact with a TNSP's obligations, incentives and market functions (p. 1).	
ENA	It is essential that the Commission considers scenarios where the Fast Frequency Response market is not sufficiently ready or established within the 3 year timeframe currently estimated as the end of the Immediate Package (p. 12).	The Commission will consider this proposal in the *Frequency control frameworks review* commencing July 2017.