REVIEW

Australian Energy Market Commission

ISSUES PAPER

Frequency Control Frameworks Review

7 November 2017

Submissions due 5 December 2017. Reference: EPR0059
Issues paper

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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 *Frequency control frameworks review* forms the next phase of work the Australian Energy Market Commission (AEMC or Commission) is undertaking to make market transformation work for consumers. The power system's needs continue to evolve and our system security and reliability frameworks need to evolve with these needs and keep pace with the technological change and innovation taking place.

To keep the lights on, the power system needs to be:

- secure – that is, able to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator
- reliable – that is, with enough generation, demand-side and network capacity to supply customers with the energy that they demand with a very high degree of confidence.

The Australian Energy Market Operator (AEMO) is responsible for maintaining power system security in the National Electricity Market (NEM). By contrast, the regulatory framework for reliability is primarily market-based. Market participants make both planning and operational decisions about capacity in response to price signals and incentives offered by the spot and contract markets.

The *Frequency control frameworks review* forms part of the AEMC's ongoing system security work program. Specifically, it represents continued consideration of, and collaboration with stakeholders on, those aspects of the *System security market frameworks review* that relate to frequency control. In June 2017 the AEMC published its final report on the *System security market frameworks review*. The review made nine recommendations for changes to market and regulatory frameworks that enable the continued take-up of new generation technologies while maintaining power system security. A summary of progress against these recommendations is provided on page vi.

A number of the recommendations made in the final report relate to rule change requests that have since been completed or are under consideration. These rules seek to address risks to power system security caused by the transition from conventional generation powered by coal, gas and hydro to generation powered by renewable sources such as wind and solar.

The review also provides the means by which to further progress a recommendation made by the AEMC in the final report of the *Distribution market model* project regarding the participation of distributed energy resources in system security frameworks.

What is frequency control and why is it important?

The power system is in a secure operating state if it is capable of withstanding the failure of a single network element or generating unit. System security events are caused by sudden equipment failure (often associated with extreme weather or bushfires) that results in the system operating outside of defined technical limits.

One of these technical limits is frequency. In Australia all generation, transmission, distribution and load components connected to the power system are standardised to operate at a nominal system frequency of 50 Hertz (Hz).

The frequency of the power system varies whenever the supply from generation does not precisely match customer demand. In the majority of situations, the changes in supply and demand are such that the corresponding variations in frequency are very small. However, sometimes, large generating units and transmission lines may trip unexpectedly and stop producing or transmitting electricity. These events tend to result in larger changes in system frequency and more significant impacts on the safety and reliability of the power system. Controlling frequency is therefore critically important.

The National Electricity Rules (NER) set up market and regulatory frameworks by which AEMO, as the body responsible for maintaining power system security, can manage frequency levels. Effective control of power system frequency requires the coordination of power system inertia[1] and the provision of a range of frequency control services. These services are intended to work together to maintain a steady power system frequency close to 50 Hz during normal operation, and to stabilise and restore the power system frequency by reacting quickly and smoothly to contingency events that cause frequency deviations.

Drivers of change

A number of drivers are creating challenges for conventional forms of frequency control in the NEM and making it more challenging for AEMO to manage power system security.

The electricity industry in Australia is undergoing fundamental change as newer types of electricity generation, such as wind and solar PV, connect and conventional forms of electricity generation, such as coal, retire. An increasing amount of these new energy technologies is being connected to distribution networks by residential and small business consumers.

The gradual shift toward more variable sources of electricity generation and consumption, and difficulties in predicting this variability, increases the potential for imbalances between supply and demand that can cause frequency disturbances.

As conventional generators retire, they reduce the inherent levels of inertia in the power system and lessen its ability to resist frequency disturbances. Similarly, the withdrawal of synchronous generation also contributes to a reduction in the

1 Inertia is a measure of the ability of the system to resist changes in frequency due to sudden changes in supply and demand. It is naturally provided by synchronous generators such as coal, hydro and gas-fired power stations.

availability of ancillary services in the NEM, including the provision of services that are used by AEMO to manage power system frequency.

Investigations undertaken by AEMO reflect that, in recent years, system frequency has increasingly been less tightly held to 50 Hz under normal operating conditions. This deterioration in the frequency performance of the power system has been attributed to a decline in frequency control voluntarily provided by generators through 'governor response'.[2]

While there is some evidence of a recent deterioration in frequency performance, the changing generation mix also presents an opportunity to consider how these newer technologies can be accommodated within the existing market and regulatory frameworks to help address system security issues. Many of these newer technologies have the potential to provide frequency control services but are not actively doing so at present.

Purpose of the review

The AEMC has self-initiated the *Frequency control frameworks review* to explore, and provide advice to the COAG Energy Council on, any changes required to the regulatory and market frameworks to meet the challenges in maintaining effective frequency control arising from, and harness the opportunities presented by, the changing generation mix in the NEM.

These challenges and opportunities have been noted by a number of organisations, including AEMO through its Future Power System Security work program, the Finkel Panel's *Independent review into the future security of the national electricity market* and by the AEMC itself through the various projects in its system security work program. The review will seek to identify and develop the changes to market and regulatory arrangements required to address the technical issues highlighted by AEMO.

Feedback from those involved in the *System security market frameworks review* indicated that many stakeholders see value in the AEMC undertaking a comprehensive review of frequency control arrangements in the NEM to determine whether they remain fit for purpose as the generation mix changes. The *Frequency control frameworks review* provides this opportunity.

Nevertheless, there are trade-offs to be made between the risks and costs of meeting system security requirements. The objective of the review is to recommend the combination of changes that are necessary to provide a secure power system at the lowest cost to consumers.

2 A governor is a device that regulates the speed of a machine, such as a generating unit. A governor can be tuned to automatically to respond to help control power system frequency changes.

Scope of the review

The terms of reference for this review noted that the scope of the review may include, but is not limited to the following issues.

1. **Primary frequency control**

The review will draw on investigations completed by AEMO into recent frequency performance and other technical advice to assess whether mandatory generator governor response requirements should be introduced to lessen the deterioration in the frequency performance of the power system. The review will also explore what consequential impacts this may have, including on AEMO's methodology for determining how the costs of procuring certain types of frequency control ancillary services (FCAS) are recovered from market participants.

2. **FCAS markets**

The review will explore the drivers of change that may mean that the existing FCAS market arrangements in the NER are not fit for purpose. For example, new technologies, such as wind farms and batteries, offer the potential for frequency response services that act much faster than traditional services to provide greater flexibility in how frequency is controlled in the NEM. The purpose of this will be to determine whether there is a need, and if so, how, to incorporate fast frequency response services within the existing arrangements. The review will also seek to explore more long-term options to facilitate a stronger co-optimisation between energy, FCAS and inertia provision in the NEM.

3. **Ramping**

Many renewable energy generation technologies are, by nature, variable. Some aspects of that variability are relatively predictable, but others are not. As the output of such generation changes, other generation sources are required to 'ramp up' or 'ramp down' so that supply matches demand in real time. Any mismatches between supply and demand can have impacts on power system frequency. The review will assess whether existing frequency control arrangements will remain fit for purpose in light of the likely increased ramping requirements as more variable generation technologies connect and existing 'dispatchable' capacity retires.

4. **Distributed energy resources**

Distributed energy resources can present challenges for AEMO in managing power system security. However, they also have the potential to help AEMO manage power system security, such as through the provision of frequency control services. The review will explore the regulatory, technical and commercial opportunities and challenges associated with the participation of distributed energy resources in system security frameworks.

The Commission will also incorporate, and be informed by, any existing work or recommendations that relate to system security (and specifically frequency control), including recommendations from the Finkel Panel that either mirror a term of reference or are otherwise within the scope of the review, including:

- requiring new generators to have fast frequency response capability[3]
- investigating and deciding on a requirement for all synchronous generators to change their governor settings to provide a more continuous control of frequency within a dead band[4]
- reviewing the framework for power system security in respect of distributed energy resources participation.[5]

Purpose of this issues paper

This issues paper represents the first stage of public consultation on the review. Its purpose is to:

- provide an overview of frequency control and the drivers for consideration of frequency control arrangements in the NEM
- set out the AEMC's framework for assessing any changes to the existing regulatory or market arrangements for frequency control
- provide the AEMC's preliminary analysis of each of the issues set out in the terms of reference for the review, drawing on the work of other organisations, including AEMO
- seek stakeholder views on the scope and materiality of each of the issues.

Stakeholder consultation

The AEMC invites stakeholder submissions on any aspect of this issues paper by 5 December 2017.

Stakeholder input on this paper will help inform the AEMC's analysis of the issues and preliminary recommendations, to be reflected in a draft report in 2018.

The AEMC also welcomes individual meetings with interested stakeholders. Those wishing to meet with the AEMC should contact Claire Richards on (02) 8296 7878 or claire.richards@aemc.gov.au.

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3 Recommendation 2.1 of the Finkel Panel review. This issue is also the subject of a rule change request currently under the AEMC's consideration. See: http://www.aemc.gov.au/Rule-Changes/Generator-technical-performance-standards

4 Recommendation 2.3 of the Finkel Panel review.

5 Recommendation 2.5 of the Finkel Panel review.

PROGRESS AGAINST RECOMMENDATIONS MADE IN *SYSTEM SECURITY MARKET FRAMEWORKS REVIEW*

RECOMMENDATION	STATUS
A STRONGER SYSTEM	
Require network service providers to maintain system strength at generator connection points above agreed minimum levels, and require new generators to 'do no harm' to previously agreed levels of system strength.	Final rule on *Managing power system fault levels* made 19 September 2017.
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.	Consultation paper on *Generator technical performance standards* rule change published 24 October 2017.
RESISTING FREQUENCY CHANGES	
Require transmission network service providers to provide minimum required levels of inertia, or alternative equivalent services.	Final rule on *Managing the rate of change of power system frequency* made 19 September 2017.
Introduce a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum required levels.	Draft rule on *Inertia ancillary service market* published 7 November 2017. Further consideration through the *Frequency control frameworks review.*
BETTER FREQUENCY CONTROL	
Assess whether mandatory governor response requirements should be introduced and investigate any consequential impacts of this.	For consideration through the *Frequency control frameworks review.*
Review the structure of FCAS markets, to consider: • any drivers for changes to the current arrangements, how to most appropriately incorporate FFR (fast frequency response) services, or alternatively enhancing incentives for FFR services within the current six second contingency service • any longer-term options to facilitate co-optimisation between FCAS and inertia provision.	
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 leading to increased demand variation within a day	
Consider placing an obligation on all new entrant plant to have fast active power control capabilities.	Consultation paper on *Generator technical performance standards* rule change published 24 October 2017.
FACILITATING THE TRANSFORMATION	
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.

Contents

1 Introduction

1.1 Background and purpose of the review

On 7 July 2017, the Australian Energy Market Commission (AEMC or Commission) initiated a review into the market and regulatory arrangements necessary to support effective control of system frequency in the National Electricity Market (NEM).[6] The purpose of the review is to explore, and provide advice to the COAG Energy Council and market participants on, any changes required to the market and regulatory frameworks to meet the challenges in maintaining effective frequency control arising from, and harness the opportunities presented by, the changing generation mix in the NEM.

These challenges and opportunities have been raised by a number of organisations, including the Australian Energy Market Operator (AEMO) through its Future Power System Security work program, the Finkel Panel through the *Independent review into the future security of the national electricity market*,[7] and by the AEMC itself through its system security work program.

The *Frequency control frameworks review* provides a means by which the AEMC can explore these issues. Specifically, it provides a vehicle through which the AEMC can progress, and seek stakeholder views on, those recommendations made in relation to frequency control in the final reports of the *System security market frameworks review* and the *Distribution market model* project.[8] These recommendations were aimed at:

- addressing current concerns with frequency performance in the NEM
- exploring how best to integrate faster frequency control services offered by new technologies into the current regulatory and market arrangements
- removing barriers to distributed energy resources participating in system security frameworks.

Feedback from those involved in the AEMC's system security work program indicated that many stakeholders see value in the AEMC undertaking a comprehensive review of frequency control arrangements in the NEM to determine whether they remain fit for purpose as the generation mix changes.

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6 The review was initiated by the AEMC under section 45 of the NEL. The term 'regulatory arrangements' refers to the National Electricity Rules and the National Electricity Law.

7 Specifically, recommendations 2.2, 2.3 and 2.5. See: http://www.environment.gov.au/energy/national-electricity-market-review

8 See: http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review and http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model.

1.2 Scope of the review

The AEMC published terms of reference on 7 July 2017,[9] which noted that the scope of the review may include, but is not limited to, the following:

1. assessing whether mandatory governor response requirements should be introduced and investigating any consequential impacts including on the methodology for determining causer pays factors for the recovery of frequency control ancillary service (FCAS) costs

2. reviewing the structure of FCAS markets to consider:

   (a) any drivers for changes to the current arrangements, how to most appropriately incorporate fast frequency response (FFR) services, or alternatively enhancing incentives for FFR services within the current six second contingency service

   (b) any longer-term options to facilitate co-optimisation between energy, FCAS and inertia provision

3. assessing 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

4. considering the potential of distributed energy resources to provide frequency control services and any other specific challenges and opportunities associated with, their participation in system security frameworks.

Items 1 - 3 above are based on recommendations made by the AEMC in the final report of the *System security market frameworks review*. Item 4 is based on a recommendation made by the AEMC in the final report of its *Distribution market model* project.

This issues paper sets out the AEMC's preliminary analysis of, and seeks stakeholder views on, these four issues.

Question 1 Scope

Are there any other issues relating to frequency control that should be included within the scope of this review?

1.3 Related work

This review follows, and is being undertaken alongside, a range of other work being carried out in the system security space by the AEMC and AEMO. Some of these

9 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Frequency-control-frameworks-review

projects are summarised below, and are referred to where relevant throughout this issues paper.

1.3.1 AEMC work

The *Frequency control frameworks review* forms part of the AEMC's integrated approach to addressing the challenges involved in maintaining system security and reliability as the NEM undergoes technological transformation. The AEMC's system security and reliability action plan,[10] comprising a number of rule changes and reviews that are either underway or complete, is focused on how the electricity system can be kept in a secure state with enough generation and demand response capability to supply consumer needs, in the context of the changing generation mix in the NEM.

Three projects in the action plan that are most relevant to the review are described in more detail below.

System security market frameworks review

The AEMC initiated the *System security market frameworks review* in July 2016 to explore what changes to the market and regulatory frameworks may be needed to support the ongoing shift towards new generation technologies in the NEM.[11]

The final report of the review, published in June 2017, made nine recommendations for changes to help deliver a more stable and secure supply of electricity. Six of these recommendations, set out below, are measures to provide for better frequency control.

1. 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).

2. Review the structure of FCAS markets, to consider:

    (a) 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

    (b) any longer-term options to facilitate co-optimisation between FCAS and inertia provision.

10 See: http://www.aemc.gov.au/News-Center/What-s-New/Announcement-Documents-(non-project)/Overview-of-the-AEMC%E2%80%99s-system-security-and-reliabi.aspx

11 See: http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review#

3. 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.

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.

5. Consider placing an obligation on all new entrant plant, whether synchronous or non-synchronous, to have fast active power control capabilities.

6. 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.

Recommendations 1 - 4 on this list are included in the terms of reference for the *Frequency control frameworks review*. In June 2016 AGL submitted a rule change request to the AEMC seeking to implement a mechanism to guide the provision of inertia for market benefits.[12] On 7 November 2017 the AEMC published a draft determination to not make a rule on this rule change request in light of the views expressed by stakeholders in submissions and analysis of the benefits of the introduction of an inertia market mechanism. However, the AEMC will continue its assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review*.

Recommendation 5 is being considered through the *Generator technical performance standards* rule change request submitted by AEMO.[13]

Recommendation 6 was considered through the *Managing the rate of change of power system frequency* rule change proposed by the South Australian Minister for Mineral Resources and Energy.[14] A final determination and final rule on this rule change request was published on 19 September 2017. The final rule, which will commence on 1 July 2018, places an obligation on TNSPs to procure minimum required levels of inertia or alternative frequency control services to meet these minimum levels.

Reliability Panel review of the frequency operating standard

The frequency requirements that AEMO must meet are set out in the frequency operating standard, which is defined in the NER and determined by the Reliability Panel.[15]

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12 See: http://www.aemc.gov.au/Rule-Changes/Inertia-Ancillary-Service-Market

13 See: http://www.aemc.gov.au/Rule-Changes/Generator-technical-performance-standards#

14 See: http://www.aemc.gov.au/Rule-Changes/Managing-the-rate-of-change-of-power-system-freque

15 For an explanation of the role and responsibilities of the Reliability Panel, see: http://www.aemc.gov.au/About-Us/Panels-committees/Reliability-panel

The Reliability Panel is undertaking a review of the frequency operating standards that apply for Tasmania and for the mainland NEM.[16] The purpose of the review is to determine whether the standards remain fit for purpose or whether changes should be made to better support power system security. The review is being undertaken in two stages:

- Stage one is addressing technical issues and changes stemming from the *Emergency frequency control schemes* rule change, which commenced on 6 April 2017.[17] The Panel published a draft determination for stage one on 12 September 2017, which proposed amendments to the frequency operating standard to include a standard for protected events, a revised requirement relating to multiple contingency events, revised definitions of certain terms and a revised limit for accumulated time error in the mainland. Submissions on the draft determination are available on the AEMC website. The Panel is scheduled to publish a final determination on stage one on 14 November 2017.

- Stage two will consider the various components of the frequency operating standard, including the settings of the frequency bands and the time requirements for maintenance and restoration of system frequency. This scope is dependent on the outcomes of the *Frequency control frameworks review*, particularly with respect to any changes to the market and regulatory arrangements relating to primary frequency control and FCAS markets. As a result the Panel will be suspending its assessment of the frequency operating standard until the *Frequency control frameworks review* is further progressed.

Reliability frameworks review

Over the past year, load shedding events on low reserve days, pre-emptive action and announcements from jurisdictional governments, as well as recommendations made by the Finkel Panel in the *Independent review into the future security of the national electricity market* have led to a greater focus on the reliability of electricity supply. At the same time, the NEM is changing at a rapid pace on both the demand and supply sides.

The AEMC is undertaking a review to assess whether the current market and regulatory reliability frameworks remain appropriate in this context.[18] An issues paper was published on 22 August 2017. Submissions on the issues paper are now closed and are available on the AEMC website. The AEMC intends to provide a progress report on this review to the COAG Energy Council by the end of 2017.

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16 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Frequency-Operating-Standard#

17 See: http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen

18 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Frameworks-Review#

1.3.2 AEMO work

The *Frequency control frameworks review* will be coordinated with the ongoing technical work being completed by AEMO on frequency control issues under the terms of the collaboration agreement between AEMO and the AEMC. This includes the work in AEMO's work program on Future Power System Security, which it established to build its understanding of the potential opportunities and challenges in operating a stable and secure power system with less synchronous generation.[19]

This review will seek to identify and develop the changes to market and regulatory arrangements required to address the technical issues highlighted by AEMO.

Of particular relevance to the *Frequency control frameworks review* is AEMO's ongoing investigation of some of the more immediate issues associated with declining frequency control performance in the NEM.[20] The AEMC will work with AEMO to coordinate the analysis and outcomes of this work with the *Frequency control frameworks review*.

AEMO is also conducting a review of the procedure for determining contribution factors, also known as the causer pays procedure. The procedure describes the calculation of market participant factors, which AEMO uses as the basis for recovering costs associated with procuring regulating FCAS.[21] The review is considering potential improvements to the settings and assumptions used in calculating market participant factors under the causer pays procedure.[22]

1.4 Stakeholder consultation

1.4.1 Submissions and comments on this issues paper

This issues paper represents the first stage of public consultation on the *Frequency control frameworks review*. The Commission invites written submissions from interested parties in response to this issues paper by **5 December 2017**. All submissions will be published on the Commission's website, subject to any claims of confidentiality.

We also welcome meetings with stakeholders. Stakeholders wishing to meet with the AEMC should contact Claire Richards on (02) 8296 7878 or at claire.richards@aemc.gov.au.

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19 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability

20 See section 3.1.4.

21 See section 2.4.2 for an explanation of regulating FCAS.

22 See: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Causer-Pays-Procedure-Consultation

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting project reference code "EPR0059".

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within three business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

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

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

1.4.2 Reference group and technical working group

A reference group comprising senior representatives of the AEMC, AEMO, the Australian Energy Regulator (AER) and the Senior Committee of Officials (SCO) has been established to provide high-level input and strategic advice to the AEMC throughout the course of the review.

The AEMC has also established a technical working group to provide technical advice to the AEMC and assist with the development of recommendations for the review. The group comprises representatives from the AER and AEMO, consumer groups, large energy users, conventional generators, renewable energy generators, retailers, energy service providers, and transmission and distribution network service providers.

1.5 Review timeline

The timeline for this review is set out in Table 1.1 below.

Table 1.1 Review timeline

Item	Date
Publication of issues paper	7 November 2017
Close of submissions on issues paper	5 December 2017
Publication of progress update to COAG Energy Council	19 December 2017
Publication of draft report	March 2018
Publication of final report	Mid-2018

1.6 Structure of this issues paper

The remainder of this issues paper is structured as follows:

- Chapter 2 provides an overview of frequency control and the existing frequency control frameworks in the NEM.
- Chapter 3 sets out the drivers of change that give the AEMC cause to review the frequency control arrangements in the NEM.
- Chapter 4 sets out the assessment framework for this review.
- Chapter 5 contemplates possible changes to existing arrangements for primary frequency control.
- Chapter 6 explores possible changes to the existing FCAS market arrangements.
- Chapter 7 looks at the opportunities and challenges associated with the participation of distributed energy resources in system security frameworks.

2 Overview of frequency control

This chapter provides an overview of:

- power system frequency
- frequency control
- how the existing regulatory framework is set up to enable frequency control.

A more detailed description of many these issues can be found in the issues paper for the *Review of the frequency operating standard*,[23] and in the interim and final reports of the *System security market frameworks review*.[24]

2.1 What is power system frequency?

The NEM, like most modern power systems, generates and transfers electricity via an alternating current (AC) power system.[25]

In an AC power system, alternating currents are accompanied (or caused) by alternating voltages. Voltage oscillates between negative and positive charge at a given rate. This can be represented by the following wave diagram, which shows how voltage shifts from positive to negative charge over a specific timeframe. The number of complete cycles that occur within one second is called the "frequency" and is measured in Hertz (Hz). The voltage waveform corresponding to a frequency of 50 Hz is shown in Figure 2.1.

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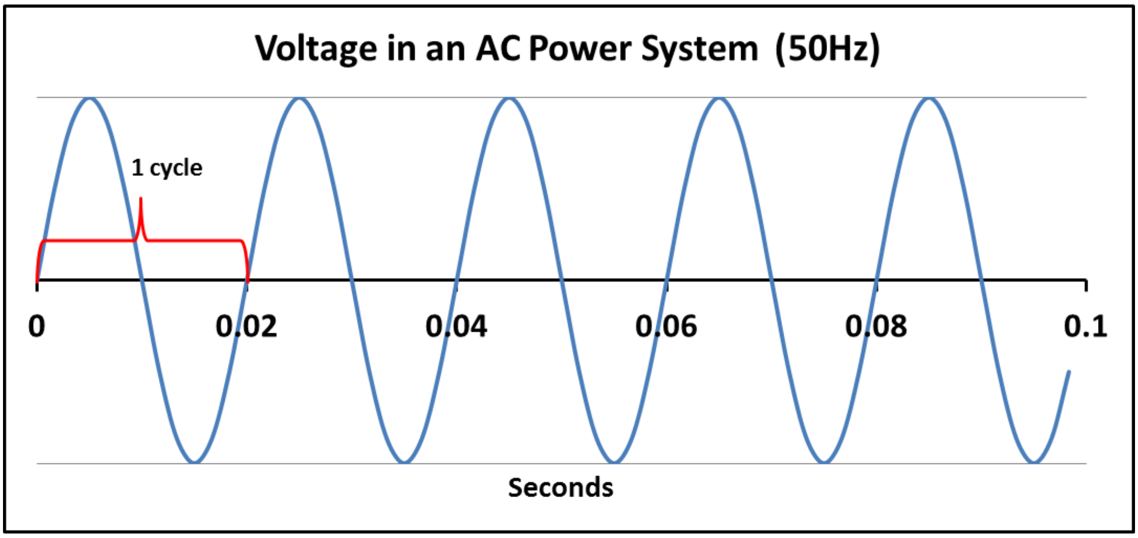
23 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Frequency-Operating-Standard#

24 See: http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review

25 Electrical power can be transferred by means of direct current (DC) or alternating current (AC). In a DC system the direction of current flow is constant, whereas in an AC system the direction of current flow periodically reverses. The power transfer in an AC system occurs through the oscillation of electrons in the transmission and distribution system, rather than through the direct movement or "flow" of electrons.

Figure 2.1 Voltage in an AC power system



In Australia all generation, transmission, distribution and load components connected to the power system are standardised to operate at a nominal system frequency of 50 Hz.[26]

This frequency is directly related to the operation of generating equipment. Electricity in an AC system has historically been produced by large generators that rotate what is effectively a very large magnet within a coil of copper wire. This rotating magnet (called the rotor) induces a current to flow in the static coils (called the stator). The speed at which the rotor spins in the stator corresponds to how "quickly" the oscillations between positive and negative occur. Put another way, the frequency of an AC system corresponds to the speed of rotation of generators. Synchronous generators have rotors that are electro-mechanically coupled with the power system and spin at a speed that is proportional to the frequency of the power system.

2.2 Frequency variation

2.2.1 What is frequency variation?

The frequency in an operating power system varies whenever the supply from generation does not precisely match customer demand. Whenever total generation is higher than total energy consumption the system frequency will rise, and vice versa.

This frequency variation is similar to how a car behaves when it begins to climb a hill after driving along a flat road. In order to maintain a constant vehicle speed as the car climbs the hill, the engine power must be increased to balance the increased "load" or the car will slow down. The engine power is increased by depressing the accelerator pedal, which supplies more fuel to the engine to maintain the vehicle speed.

26 Other power systems operate at different standard frequencies. For example, the nominal power system frequency in the United States and Canada is 60 Hz, while Europe and the United Kingdom operate their power systems at 50 Hz.

In a similar way, power system frequency is affected by changes in customer demand, or load, relative to the amount of available generation. To maintain the "speed" - that is, the frequency - of the system following an imbalance of generation relative to load (analogous to the car beginning to climb the hill), more energy is required from all generators (depressing the accelerator pedal) to maintain the system frequency at 50 Hz.

In the majority of situations, the changes in supply and demand that cause frequency variations are such that the corresponding variations in frequency are very small. Household appliances and industrial load being switched on and off are all examples of minor changes in demand happening all the time. The quantity of electricity supplied into the network may also change due to the variable output of wind and solar generation.[27]

On occasion, changes in supply and demand can be more significant. Large generating units and transmission lines may trip unexpectedly and suddenly stop producing or transmitting electricity. Similar outcomes can occur on the demand side, if large industrial facilities trip off the system and suddenly stop consuming. These are referred to in the NER as contingency events. They are less common but tend to result in more significant changes in system frequency.

2.2.2 What are the consequences of frequency variation?

All equipment connected to the power system is designed to operate at or near the nominal frequency of 50 Hz. For example, a typical steam turbine can operate continuously at ±1 per cent away from the nominal frequency, or within a range of 49.5-50.5 Hz. Most consumer electronic equipment is designed to operate within a tolerance range of ±5 per cent away from the nominal frequency, or 47.5-52.5 Hz.

The tolerance of different machines or devices to frequency deviations varies both in terms of the size of a divergence that can be withstood and the length of time that the deviation can be ridden through. Large or lengthy deviations outside of these tolerance limits can increase wear and tear on this equipment, and could have significant impacts on its safety and functional efficiency. For example, steam turbines are generally only designed to withstand short periods of operation outside of its tolerance range, with a practical working limit reached at around ±5 per cent or 47.5-52.5 Hz.[28] The turbine may experience damaging vibrations outside this operating frequency range and, if allowed to operate at an excessively high speed, there is risk of a catastrophic equipment failure.

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27 In practice, AEMO forecasts the expected demand and the output of variable renewable generation as part of its operation of the wholesale electricity market. Operationally, minor frequency deviation can be a result of actual demand or generation output varying from the demand or generation output as forecast. This forecast error issue has been raised in AEMO’s Future Power System Security work program through the following report: AEMO, Visibility of Distributed Energy Resources, January 2017, p.14.

28 General Electric Company, 1974, Load Shedding, Load Restoration and Generator Protection Using Solid-state and Electromechanical Under-frequency Relays – Section 4 – Protection of steam turbine – generators during abnormal frequency conditions.

As a self-protection mechanism, generation and transmission equipment is designed to disconnect from the power system during periods of prolonged or excessive deviations from the nominal system frequency. However, the disconnection of generation due to low system frequency would worsen the supply-demand imbalance that originally caused the frequency disturbance and potentially lead to a cascading system failure and a major blackout. Controlling frequency is therefore critically important to maintaining a secure and reliable power system.

2.3 What is frequency control and why is it important?

Effective control of power system frequency requires the coordination of power system **inertia** and the provision of a range of **frequency control ancillary services** (FCAS). These services are intended to work together to maintain a steady power system frequency close to 50 Hz during normal operation, and to react quickly and smoothly to contingency events that cause frequency deviations to stabilise and restore the power system frequency.

As explained above, conventional electricity generators, like hydro, coal and gas, operate with large spinning turbines that are synchronised to the frequency of the grid. Changes to the balance of supply and demand for electricity can act to speed up or slow down the frequency of the system. In each synchronous generating unit, the large rotating mass of the turbine and alternator has a physical inertia which must be overcome in order to increase or decrease the rate at which the generator is spinning. In this manner, large conventional generators that are synchronised to the system act to dampen changes in system frequency. The greater the number of generators synchronised to the system, the higher the system inertia will be and the greater the ability of the system to resist changes in frequency due to sudden changes in supply and demand.

The rate at which the frequency changes following a contingency event, such as the disconnection of a large generating unit, determines the amount of time that is available to arrest the decline or increase in frequency before it moves outside of the permitted operating bands described in the frequency operating standard.[29]

The **rate of change of frequency** is proportional to the size of the sudden change in supply or demand as a result of the contingency event and inversely proportional to the level of system inertia at the time that the contingency occurs. The greater the size of the contingency event, or the lower the system inertia, the faster the frequency will change. More inertia in the power system means a slower initial decline of power system frequency. However, inertia is not able to stabilise or restore the power system frequency on its own.

FCAS, described in more detail in section 2.4.2, are services procured by AEMO to alter the supply-demand balance so that system frequency stays at or near the nominal frequency of 50 Hz.

29 The frequency operating standard is explained in section 2.4.1.

The coordination of inertia and FCAS services is often referred to as "integrated frequency control", which comprises primary, secondary and tertiary frequency control.

Primary frequency control provides the initial response to frequency disturbances. It reacts almost instantaneously to changes in system frequency outside predetermined set points. This response is enabled by local frequency measurement and the automatic modification of the output of generating units or customer demand.[30] The modification of generator output is generally provided through the generator governor systems that regulate the output of generating units.[31]

In the NEM, primary frequency control is only required to be provided by contingency FCAS,[32] and is voluntarily provided by generator governor response.[33]

Secondary frequency control refers to services that are directed, in real time, to respond to frequency disturbances by the system operator. This direction may occur via either the Automatic Generation Control (AGC) system as is the case for regulating FCAS in the NEM or via manual direction. Secondary frequency control services are intended to correct the power system frequency over a period of minutes.[34]

Tertiary frequency control refers to reserve generation capacity that is able to be utilised to reset the primary and secondary frequency control services. This capacity is dispatched via the NEM dispatch engine, which matches generation supply with demand every 5 minutes.[35]

The interaction of inertia with primary and secondary frequency control is shown below in Figure 2.2.

30 International Council on Large Electric Systems (CIGRE), 2010, *Ancillary Services: an overview of International Practices*, Working Group C5.06, pp.7-8.

31 Primary frequency control can be broken down into: continuous primary services that help control power system frequency during normal operation; and primary services that act following larger contingency events. These services are discussed in more detail in chapter 5.

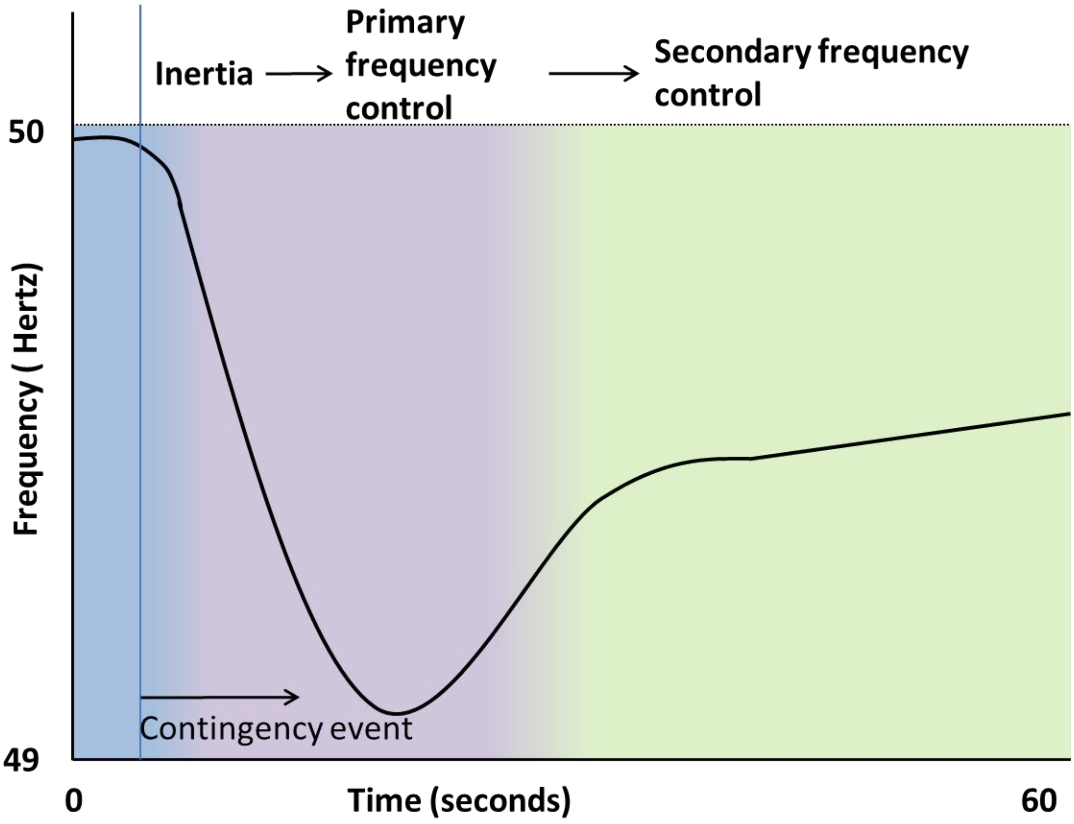
32 Contingency FCAS is explained in section 2.4.2.

33 Generator governor response is explained in section 3.1.4 and in chapter 5.

34 Ibid., p. 8.

35 Ibid., p. 9.

Figure 2.2 **Interaction between inertia, and primary and secondary frequency control**



2.4 How is the existing framework set up to enable frequency control?

System security is necessary for the efficient functioning of the power system. Under the National Electricity Law (NEL), AEMO's statutory functions include maintaining and improving power system security.[36]

AEMO is required under the National Electricity Rules (NER) to operate and maintain the power system in a "secure operating state". In order for the electricity system to remain in a secure operating state, there are a number of physical parameters that must be maintained within a defined operating range. An operational power system must also be able to operate satisfactorily under a range of conditions, including in the event of foreseeable contingency events, such as the failure of a single transmission element or generator.

Specifically, AEMO is responsible for maintaining the power system in a secure operating state by satisfying the following two conditions:

1. The system parameters, including frequency, voltage and current flows are within the operational limits of the system elements, referred to as a "satisfactory operating state".

36 See section 49(1)(e) of the NEL.

2. The system is able to recover from a credible contingency event or a protected event, in accordance with the power system security standards.[37]

Frequency control is a key element of power system security. To maintain a stable system frequency, AEMO must instantaneously balance the supply of electricity into the power system against consumption of electricity at all times. As explained in section 2.2, when there is more generation than load, the frequency will tend to increase. When there is more load than generation, the frequency will tend to fall.

A number of components of the regulatory framework are in place to enable AEMO to meet its obligations with respect to frequency control. These are set out below.

2.4.1 Frequency operating standard

The frequency requirements that AEMO must meet are set out in the frequency operating standard, which is defined in the NER and determined by the Reliability Panel. The purpose of the frequency operating standard is to define the range of allowable frequencies for the electricity power system under different conditions, including normal operation and following contingencies. Generator, network and end-user equipment must be capable of operating within the range of frequencies defined by the frequency operating standard, while AEMO is responsible for maintaining the frequency within the ranges defined by the standard. These requirements then inform how AEMO operates the power system, including through applying constraints to the dispatch of generation or procuring ancillary services.

The frequency operating standard currently consists of two separate standards - one for the mainland NEM and one for Tasmania - to reflect the different physical and market characteristics of the Tasmanian region as opposed to the mainland NEM. The power system frequency is consistent throughout the mainland interconnected transmission network, with frequency centrally controlled during normal operation and the impact and response to frequency disturbances spread throughout the network and the corresponding market participants. Tasmania is connected to the NEM via Basslink, a high voltage DC undersea cable. This cable allows power transfer between the mainland NEM and Tasmania but does not transfer the AC frequency between the two regions. As a result, the Tasmanian power system operates at its own electrical frequency separate from the mainland NEM, but still at a frequency of 50 Hz.

Figure 2.3 and Figure 2.4 set out the frequency bands defined in the frequency operating standard for the mainland NEM and Tasmania.

37 Clause 4.2.4(a) of the NER.

Figure 2.3 Frequency bands - mainland NEM

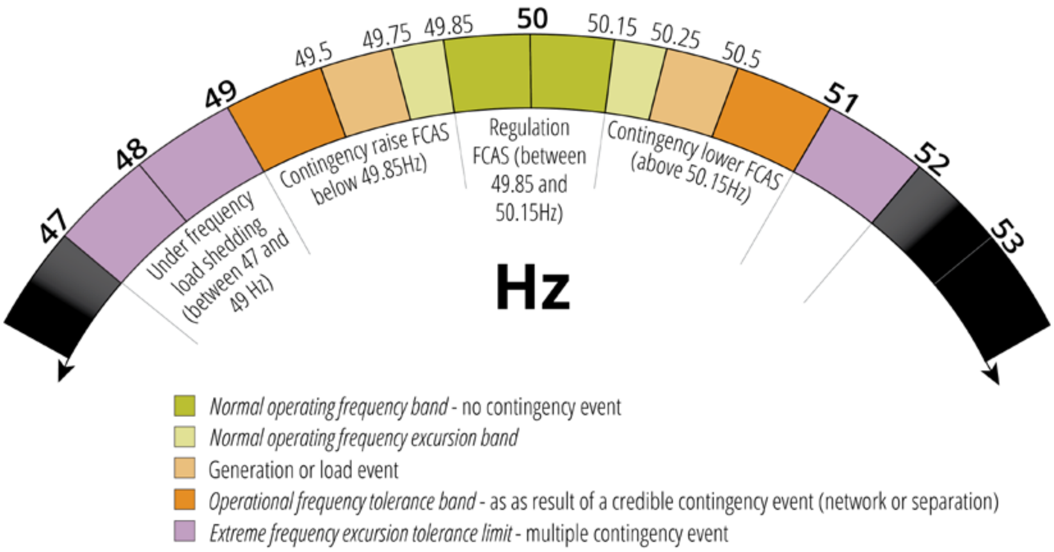
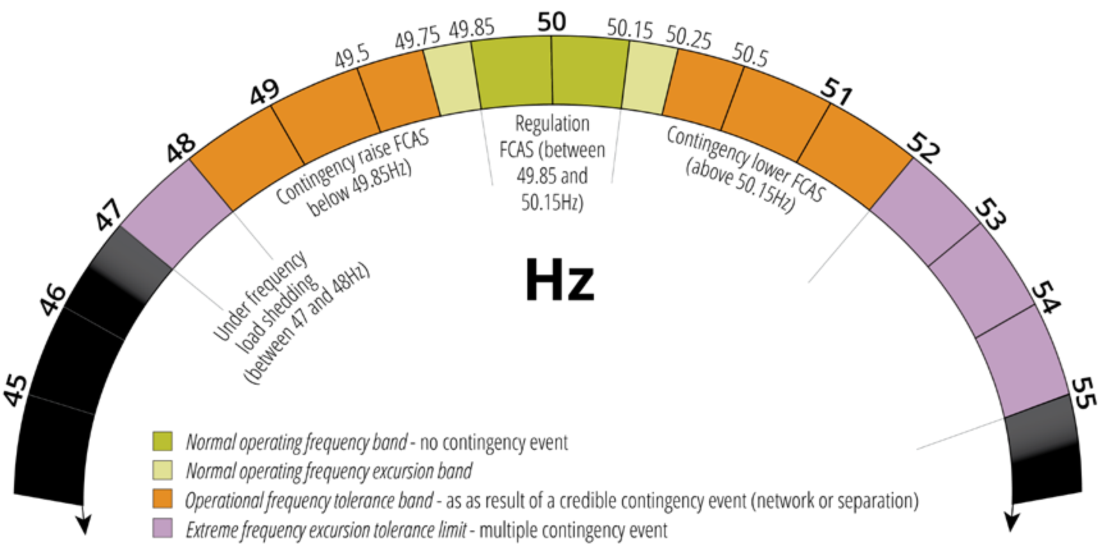


Figure 2.4 Frequency bands - Tasmania



2.4.2 Frequency control ancillary services

Ancillary services under clause 3.11.1 of the NER are services:

> "…that are essential to the management of power system security, facilitate orderly trading in electricity and ensure that electricity supplies are of acceptable quality."

There are two types of ancillary services provided in the NEM: market and non-market ancillary services. Non-market ancillary services provide (black) system restart and network support (e.g. voltage control) services, and are provided by parties under contract with AEMO.

Market ancillary services are concerned with the timely injection (or reduction) of active power to arrest a change in frequency. AEMO operates the wholesale electricity market, which dispatches electricity generation to meet the expected demand for electricity every five minutes. Some imbalance between supply and demand is expected to occur within the five minute dispatch process which, as explained in section 2.2, can cause frequency variations.

Market ancillary services are procured by AEMO to increase or decrease active power over a timeframe that maintains the technical performance of the power system, in this case, that satisfies the frequency operating standard. AEMO's Market Ancillary Services Specification (MASS) defines the technical requirements for the provision of FCAS.[38] These services are generally referred to as frequency control ancillary services (FCAS) although this is not a defined term under the NER.

This review is focused on issues surrounding frequency control in the NEM, and therefore focuses on the arrangements for the provision of FCAS.

There are two types of FCAS: regulating and contingency.

Regulating FCAS

The power system frequency is continually fluctuating in response to changing generation and load conditions. To manage this fluctuation, AEMO continuously monitors the power system frequency and sends out "raise" or "lower" signals to registered generators that are dispatched to correct small frequency deviations. The services provided by these generators are called regulating FCAS, as they regulate the power system frequency to keep it within the normal operating frequency band defined in the frequency operating standard.

There are two types of regulating FCAS:

1. Regulating raise service. Used to correct a minor drop in frequency.

2. Regulating lower service. Used to correct a minor rise in frequency.

Collectively, these two services are defined as 'regulation services' in the NER. Note that AEMO often refers to regulating FCAS as 'regulation FCAS'.

The operation of regulating FCAS is coordinated by AEMO's AGC system. The AGC monitors minor changes in the power system frequency and adjusts the output of regulating FCAS generating units accordingly.

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38 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Market-ancillary-servicesspecifications-

Contingency FCAS

Under the frequency operating standard, AEMO must ensure that, following a credible contingency event, the frequency deviation remains within the contingency band and is returned to the normal operating band within five minutes. Contingency FCAS is procured by AEMO to respond to larger deviations in power system frequency that are usually the result of contingency events such as the tripping of a large generator or load. Providers of contingency FCAS respond automatically to deviations in the power system frequency outside of the normal operating frequency band.[39]

Contingency FCAS is divided into raise and lower services at three different speeds of response and sustain time: fast (6 seconds), slow (60 seconds) and delayed (5 mins). As such, there are six distinct contingency FCAS services:

1. Fast raise service. 6 second response to arrest a major drop in frequency following a contingency event.

2. Fast lower service. 6 second response to arrest a major rise in frequency following a contingency event.

3. Slow raise service. 60 second response to stabilise frequency following a major drop in frequency.

4. Slow lower service. 60 second response to stabilise frequency following a major rise in frequency.

5. Delayed raise service. 5 minute response to recover frequency to the normal operating band following a major drop in frequency.

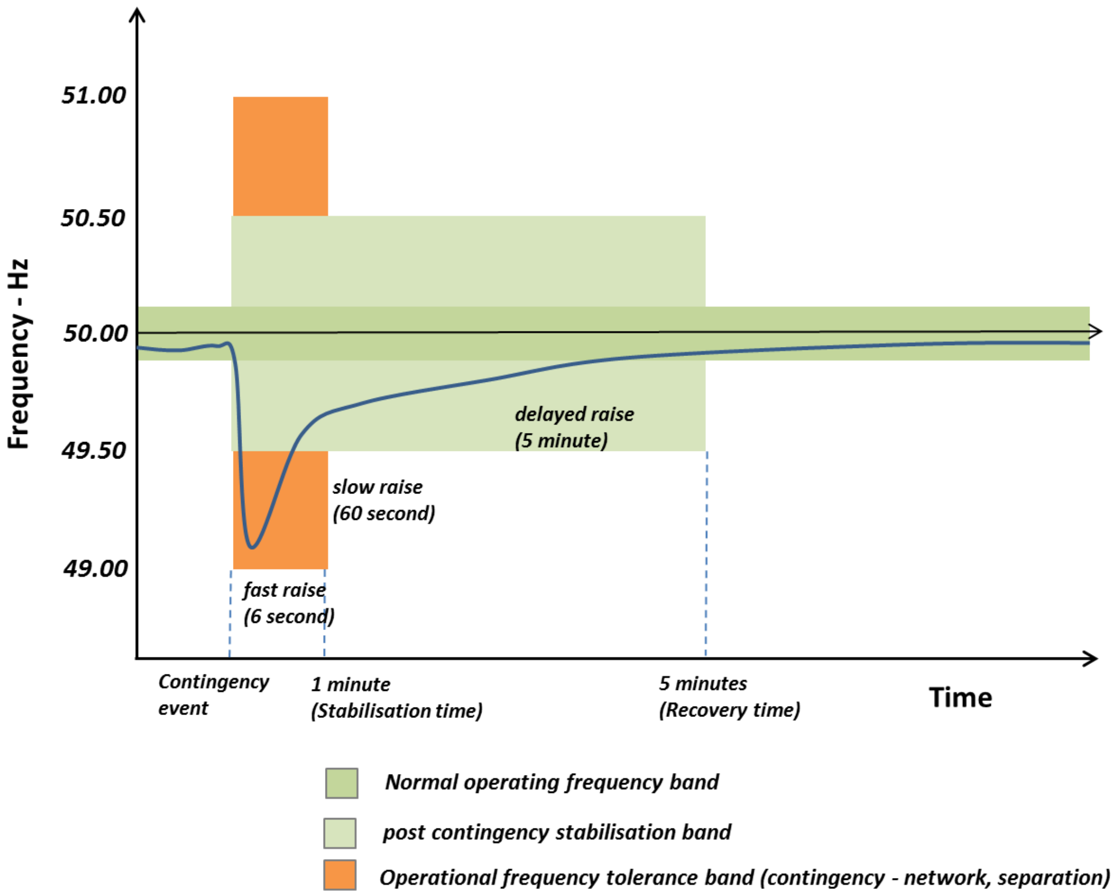
6. Delayed lower service. 5 minute response to recover frequency to the normal operating band following a major rise in frequency.[40]

In response to a contingency event, each type of contingency FCAS will work together to recover the power system frequency within the applicable frequency bands and time frames defined in the frequency operating standard, as displayed in Figure 2.5.

39 Providers of contingency FCAS respond automatically based on a local measurement of system frequency, in comparison to regulating FCAS which is coordinated by AEMO based on a centralised measurement of system frequency.

40 AEMO, Guide to ancillary services in the national electricity market, 2015, p. 8.

Figure 2.5 Frequency deviation and FCAS response



FCAS markets

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.[41]

There are eight markets in the NEM for FCAS, one for each type of regulating and contingency service. Participants must register with AEMO to participate in each distinct FCAS market. Once registered, a service provider can participate in an FCAS market by submitting an appropriate FCAS offer or bid for that service.

AEMO determines the amount of FCAS that is required to manage the power system frequency in accordance with the frequency operating standard. For each five minute dispatch interval, the national electricity market dispatch engine enables sufficient FCAS in each market, and the price for each service is set by the highest enabled bid in each case.

Providers of FCAS are paid for the amount of FCAS in terms of dollars per megawatt enabled per hour. That is, generators receive a payment irrespective of whether the

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

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.

The recovery of AEMO's payments to providers for regulating FCAS is based upon the "causer pays" methodology. Under this methodology the response of measured generators and loads to frequency deviations is monitored and used to determine a series of causer pays factors.[42]

The costs of contingency raise services are recovered from Market Generators, as these services are required to manage the loss of the largest generator on the system. The costs of contingency lower services are recovered from Market Customers, as these services are required to manage the loss of the largest load or transmission element on the system.

2.4.3 Generator technical performance standards

Equipment that makes up and connects to the power system must perform to certain levels of technical capability. This helps AEMO maintain the power system in a secure and safe operating state and manage the risk of major supply disruptions. The levels of performance for equipment connecting to the power system are set out in performance standards for each connection. These performance standards are reached through a negotiating framework that is set out in the NER.

'Access standards' in the NER define the range of the technical requirements for the operation of equipment when negotiating a connection. These access standards include a range from the minimum to the automatic access standard. For each technical requirement defined by the access standards, a connection applicant must either:

- meet the automatic access standard, in which case the equipment will not be denied access because of that technical requirement; or
- negotiate a standard of performance with the local network service provider[43] that is at or above the minimum access standard and below the automatic access standard.

The generator access standards in the NER cover a range of technical capabilities for connecting generators, including, among other things, frequency control and response to frequency disturbances during and following contingency events.[44]

42 Causer pays factors are discussed in more detail in chapter 5.

43 The connection applicant may also need to negotiate with AEMO on access standards that are AEMO advisory matters.

44 This section summarises the requirements in the NER that apply to generators connected after the 8 March 2007, when the National Electricity Amendment (Technical Standards for Wind Generation and other Generator Connections) Rule was made. Chapter 11 of the NER contains a transitional rule, clause 11.10.3, that allows for pre-existing access standards to continue to apply.

Broadly, the automatic access standard that applies to generator frequency control is that:

- the generating system's output should not worsen any frequency deviation
- the generating system must be capable of automatically increasing or decreasing its output to help restore the system frequency to within the normal operating frequency band.[45]

The minimum access standard for generator frequency control does not directly refer to the frequency operating standard. It requires that a generator's output must not:

- increase in response to a rise in system frequency
- decrease more than 2 per cent per Hz in response to fall in system frequency.[46]

2.4.4 Emergency frequency control schemes

Emergency frequency control schemes are schemes that help restore power system frequency in the event of extreme power system events, such as the simultaneous failure of multiple generators and/or transmission elements. The operational goal of emergency frequency control schemes is to act automatically to arrest any severe frequency deviation prior to breaching the extreme frequency excursion tolerance limit, and hence avoid a cascading failure and widespread blackout.

Traditional emergency frequency control schemes operate via frequency sensing relays that detect a frequency deviation beyond a pre-defined set point and act to disconnect any connected generation or load behind the relay. However, schemes can be set up to operate based on the occurrence of a particular contingency event, such as the failure of an interconnector. The installation and operation of emergency frequency control schemes is the responsibility of the relevant transmission network service provider (TNSP), while AEMO coordinates the overall performance of the schemes as part of its system security responsibility.

Emergency frequency control schemes were the subject of a rule change request submitted by the South Australian Minister for Energy in July 2016.[47] The AEMC published a final rule determination on this rule change request in March 2017, which sets out a revised framework for the management of emergency frequency control schemes. The AEMC is not aware of any reason to revisit these new arrangements and, as such, emergency frequency control schemes are not considered or discussed in detail in this issues paper.

45 See S5.2.5.11(b) of the NER.

46 See S5.2.5.11(c) of the NER.

47 See: http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen

3 Drivers of change

The electricity industry in Australia is undergoing fundamental change as newer types of electricity generation, such as wind and solar, connect and conventional forms of electricity generation, such as coal, retire. A formerly passive demand side is becoming increasingly engaged in energy markets through the uptake of new technologies and services, such as solar PV, storage and demand response. This transformation has potential implications for the management of power system frequency, driven both by a reduction in frequency control capability and an increased potential for imbalances between the supply of, and demand for, electricity.

This chapter explores the declining levels of power system inertia in the NEM and the reduction in the levels of frequency control capability provided by generators, including regulation and contingency FCAS, and the reduction in primary frequency control provided from generator governors.

This chapter also explores the increased variability in supply from intermittent generating technologies, which is creating challenges for AEMO's ability to forecast demand and match generator output from dispatchable sources accordingly.

3.1 Changing generation mix

3.1.1 Integration of new technologies

As the generation fleet changes and the needs of the power system evolve, the required services needed to maintain power system security are also likely to evolve.

The existing frequency control frameworks were largely established when the technical characteristics and capabilities of the generation mix were very different. There may now be opportunities for the new energy technologies being connected to provide services that help support power system security, including frequency control.

These challenges and opportunities call into question the need for changes to frequency control frameworks to make sure they remain suitable and sufficiently flexible so as not to preclude the participation of emerging technologies.

3.1.2 Lower levels of inertia

Inertia is naturally provided by conventional electricity generation technologies, such as hydro, coal-fired and gas-fired power stations, that operate with large spinning turbines and alternators that are synchronised to the frequency of the grid. These generators have significant physical inertia and support the stability of the power system by working together to resist frequency disturbances in the power system. Inertia determines how fast frequency changes immediately following a contingency event. This is called the initial rate of change of frequency (RoCoF).

Newer electricity generation technologies, such as wind and solar PV, are connected to the power system via electrical inverters and are not synchronised to the grid. International experience suggests that it is currently not 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.

Historically, most generation in the NEM has been synchronous and, as such, the inertia provided by these generators has not been separately valued. However, as the generation mix shifts to include smaller and more non-synchronous generation, inertia is not provided as a matter of course. This is making it increasingly challenging for AEMO to maintain the power system in a secure operating state.[48]

3.1.3 Reduction in availability of regulating and contingency FCAS

The withdrawal of synchronous generation also contributes to a reduction in the availability of ancillary services in the NEM, including FCAS. Additionally, the increasing variability of supply and demand is likely to be met with increased frequency control requirements from the market.

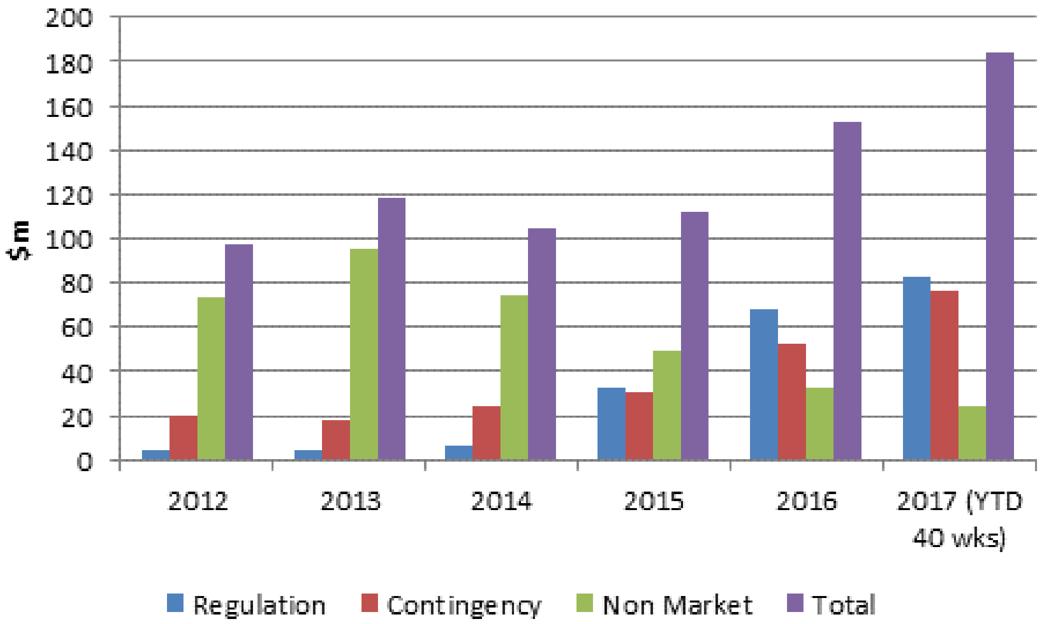
The market has historically attracted regulation and contingency FCAS from synchronous generation. If this synchronous generation is displaced (either permanently or temporarily), the level of FCAS it provided will have to be procured from other sources, which the market has not attracted to date.

The cost of delivering ancillary services in the NEM (both market and non-market services) has increased significantly over recent years from roughly $100 million in 2012, to a year to date (40 weeks) total of over $180 million in 2017, as shown in Figure 3.1.[49]

48 Recent declining levels of inertia is also the subject of the *Managing the rate of change of power system frequency* and *Inertia ancillary service market* rule change requests. See the AEMC website for further information about these rule changes.

49 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Ancillary-Services/Ancillary-Services-Payments-and-Recovery

Figure 3.1 Ancillary service costs 2012-2017 by category



The increase in total costs of ancillary services over the period from 2012 to 2017 (part year) can be disaggregated with respect to the costs of the different categories of ancillary services. There was a net increase in the cost of market (or FCAS) services of $134.6 million over the period, which was partly offset by a reduction of $48.5 million in non-market ancillary services, due to a reduction in the cost of system restart and voltage support services.

The increased cost of market services can primarily be attributed to the increase in the cost of regulation services which have increased by 16 times, or approximately $78 million over the period. As regulation services are provided through a market mechanism, this increase reflects the market clearing prices bid by generators to provide this service and, in the absence of significant market power, can be assumed to reflect the efficient cost of providing the service and to signal the opportunity for new entrants to participate in this market. This change in costs is presented in the following table.

Table 3.1 Change in ancillary service costs 2012-2017[50]

Category	2012	2017 (YTD 40 wks)	Change ($m)	Percentage change
Regulation	4.9	82.6	77.7	1590%
Contingency	19.7	76.6	56.9	289%

50 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Ancillary-Services/Ancillary-Services-Payments-and-Recovery

Category	2012	2017 (YTD 40 wks)	Change ($m)	Percentage change
Non-market	73.2	24.6	-48.5	-66%
Total	97.8	183.8	86.0	88%

The magnitude of the increase in cost of market ancillary services is highlighted when assessed as a percentage of the value of wholesale energy market transactions. In 2012, the cost of wholesale energy was around $8 billion increasing to around $12 billion in 2017 (scaled for a full year). Market ancillary service costs as a percentage of wholesale energy market costs have therefore increased from around 0.2 per cent to 1.6 per cent over this period.

In the event that insufficient FCAS is available to manage the risk of a credible contingency event, AEMO may use other means to maintain the secure operation of the power system. Alternative means include the pre-emptive constraining of interconnector flows or generation output to reduce the size of the possible contingency event, and/or to require additional reserve capacity to be available to respond to a contingency event.

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. 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. Such fast frequency response (FFR) services would act to arrest the frequency change more quickly than the current fastest acting contingency FCAS service, which has a response time of up to six seconds. Although FFR services could be procured through the existing six second FCAS contingency service, this does not necessarily recognise any enhanced value that might be associated with the faster response. Possible solutions to this issue are set out in chapter 6.

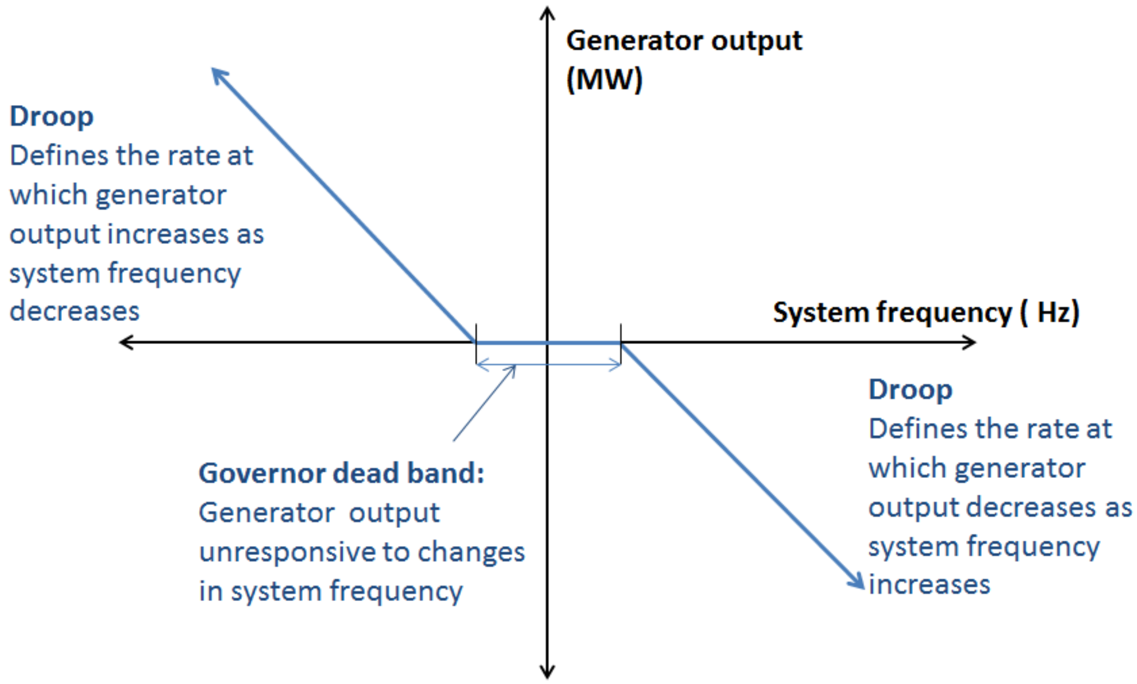
3.1.4 Reduction in primary frequency control provided by governor response

What is governor response and what is its purpose?

A governor is a part of a generator control system that regulates the electrical output of a generating unit or generating system. In the context of frequency control, governors can be used to respond to frequency changes through changes in generating output. Governors can be enabled to be automatically responsive to changes in the power system frequency outside of a pre-determined dead band. The dead band specifies the frequency range within which the governor is unresponsive to power system frequency changes, and within which the power output from the generator is kept steady, as shown in Figure 3.2.

Droop is an indication of the change in generator output for a given change in power system frequency. Given a fall in power system frequency, the droop setting refers to the percentage frequency change that will result in the output of a generator increasing to 100 per cent of its rated capacity. For example given a 100 MW generator with a droop setting of 5 per cent and assuming that the generator is operating with sufficient headroom, a fall in power system frequency of 0.05 Hz or (0.1 per cent of 50 Hz) will result in an increase of power output from the generator of 2MW. Similarly following an increase of power system frequency of 0.05 Hz the same generator would decrease its power output by 2MW.

Figure 3.2 Generator frequency response and the governor dead band



In the NEM, generator governor response is responsible for the delivery of contingency FCAS from generators that are enabled via the FCAS markets. This service is activated at frequency set-points outside the normal operating frequency band (49.85 Hz to 50.15 Hz). Generators that are not enabled to provide contingency FCAS, are not required to provide a primary response to a change in the power system frequency.[51] The response of a generating system to frequency changes is specified in the generator performance standards that form part of a generator's connection agreement. A summary of the generator performance standards that apply for frequency control is provided in section 2.4.3

51 Schedule 5.2.5.11 of the NER specifies the minimum and automatic performance standards that apply to how a generating system must respond to changes in power system frequency.

History of governor response in the NEM

At the start of the market, ancillary services were procured through a tender process and long term contracts between NEMMCO[52] and service providers.[53] 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 in 1999, the existing spot markets were introduced for the enablement of contingency FCAS. 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 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 recommended that this obligation be removed. The justification for this was that mandatory provision represented a "hidden subsidy" and that "governor capability should be fully paid for under the FCAS arrangements proposed".[54]

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 dead bands.

Prior to November 2003 the National Electricity Code included a requirement mandating that generators have an operational governor system that automatically responded to frequency. This "governor system" requirement, set out in schedule 5.2.6.4 of the code, was removed in November 2003 and replaced with automatic and minimum access standards that require generators to have the capability to respond to frequency disturbances.[55]

The mandatory governor system requirement applied to all generating units with a rated capacity of 100MW and above. The requirement specified key performance criteria relating to the governor responses, which are set out in Box 3.1.[56]

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

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

54 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.

55 NECA, 2003, Technical standards code changes – Gazette notice, S5.2.11, 27 March 2003 The automatic and minimum access standards set out in S5.2.5.11 of the code version 1.0, amendment 7.7 form the basis of the current S5.2.5.11 in the NER.

56 Ibid., S5.2.6.4.

Box 3.1 Technical performance requirements of governor systems under the National Electricity Code prior to 16 November 2003

- The response of the generating unit to system frequency excursion should be capable of :
  - achieving an increase in the generating unit's active power output of 2% per 0.1 Hz reduction in system frequency for any initial output up to 85% of rated output.
  - reduction in the generating unit's active power output of 2% per 0.1 Hz increase in system frequency provided the latter does not require operation below technical minimum.
- Generating units must be capable of achieving an increase in output of at least 5% of their rating for operation below 85% of output. For operation above 85% of rated load, the required increase will be reduced linearly with generating unit output from 5% to zero at rated load. The generating unit will not be required to increase output above rated load.
- Generating units must be capable of achieving a decrease in output of at least 10% of their rating for operation at all levels above their technical minimum loading level as advised in the registered bid and offer data.
- The dead band of a generating unit (being the sum of the increase and the decrease in system frequency before a measurable change in the generating unit’s active power output occurs) must be less than 0.1 Hz.
- For any frequency disturbance a generating unit must be capable of achieving at least 90% of the maximum response to power generation expected according to the droop characteristic within 60 seconds and sustain the response for a minimum of 30 seconds.
- When a generating unit is operating in a mode such that it is insensitive to frequency variations (including pressure control or turbine follower for a thermal generator), the Generator must apply a dead band of not greater than 0.25 Hz to ensure that the generating unit will respond for frequency excursions outside the normal operating frequency band.

Evidence of degradation and AEMO’s engagement of DIgSILENT

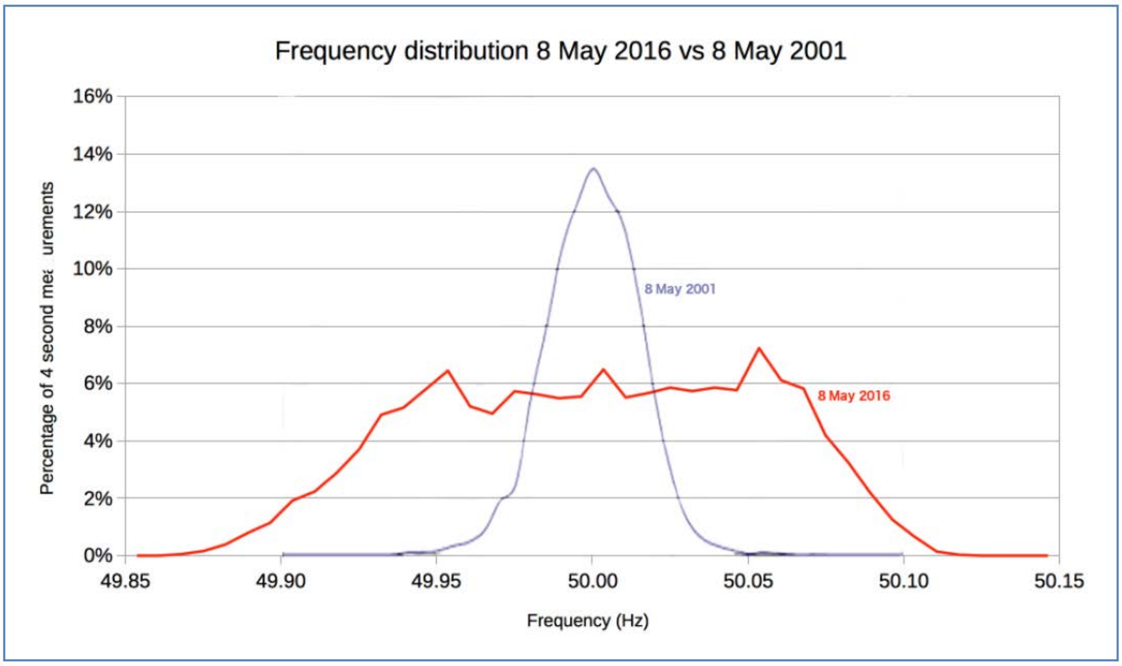
The Commission is aware that the frequency performance of the power system has declined in recent times. Specifically, there is some evidence that the power system frequency increasingly operates further away from the nominal frequency of 50 Hz than has historically been the case.

This issue was initially highlighted by Pacific Hydro in its submission to the Commission's Interim Report for the *System security market frameworks review*.[57] In its submission, Pacific Hydro highlighted the extent to which frequency has changed by comparing the system wide frequency profile on 8 May 2016 relative to the same day in 2001.[58]

This comparison is shown below in Figure 3.3. The frequency profile shows the percentage of time that the power system frequency is measured at a given frequency value. The distribution profile for 8 May 2016 shows a clear flattening of the distribution profile relative to 2001.

The Commission notes that, in this example, both frequency profiles demonstrate outcomes that are compliant with the frequency operating standard, in that the amount of time that the frequency is outside of the normal operating frequency band (49.85 – 50.15 Hz) is less than 1 per cent.

Figure 3.3 Frequency distribution profile NEM mainland: 2001 - 2016[59]



In May 2017 AEMO published frequency distribution charts showing the long term trend between 2007 and 2017 for the NEM mainland (Figure 3.4) and between 2012 and 2017 for Tasmania (Figure 3.5). These charts reinforce the long term trend of a "flattening" of the frequency distribution within the normal operating frequency band during normal power system operation.

57 Pacific Hydro, Submission to the *System Security Market Frameworks Review* – Interim report, 6 February 2017.

58 The Commission notes that 8 May in 2001 fell on a Tuesday and 8 May 2016 fell on a Sunday. A typical weekend load profile is likely to be different from a typical weekday load profile.

59 Pacific Hydro, 6 February 2017, Submission to the AEMC's Interim Report – *System Security Market Frameworks Review*, p. 4.

Figure 3.4 NEM Mainland frequency distribution – 2007-2017[60]

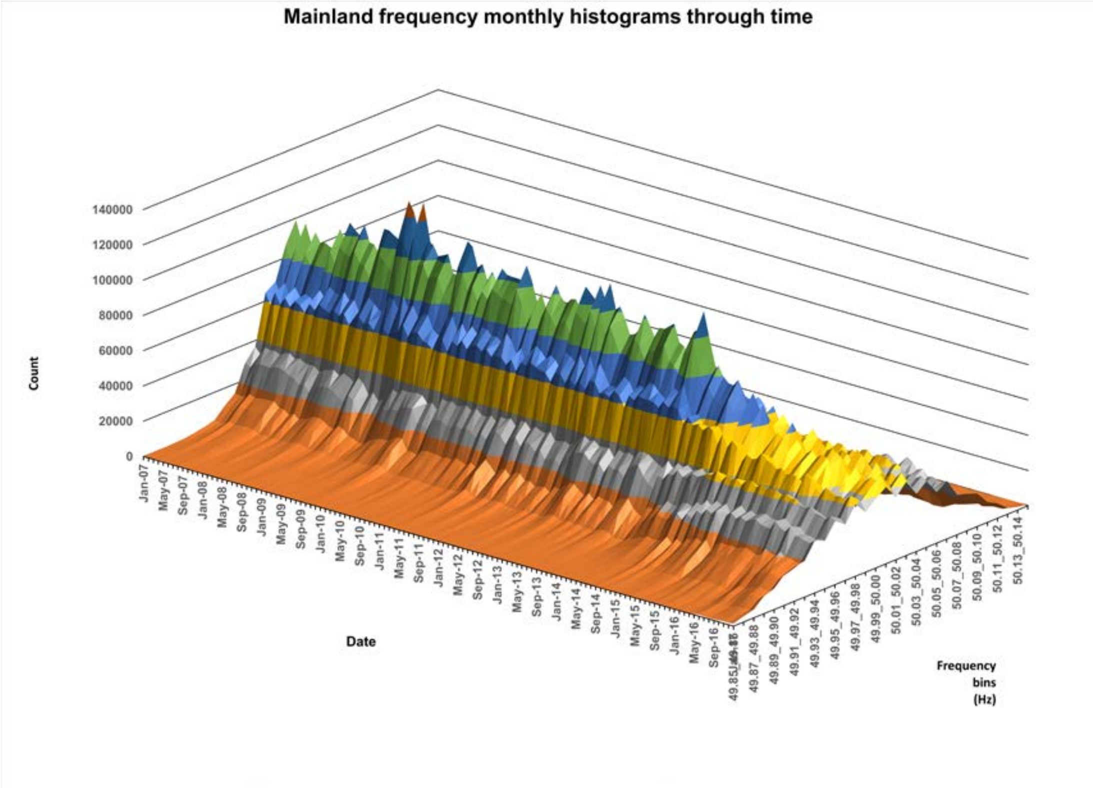
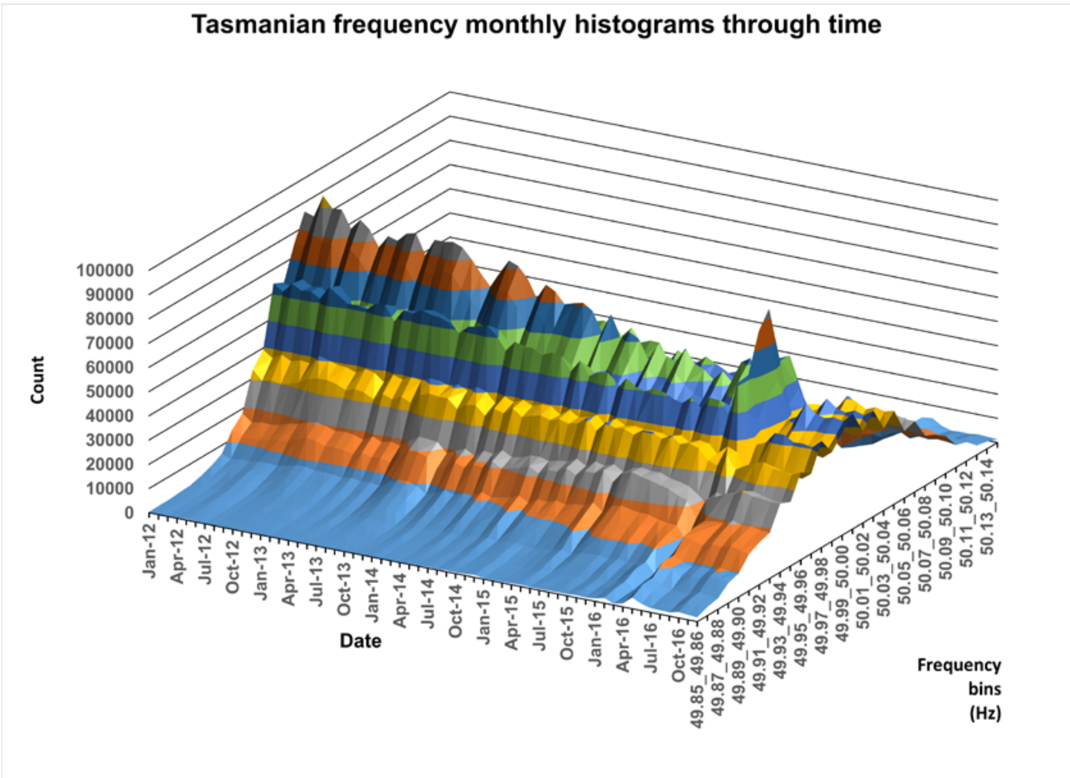


Figure 3.5 Tasmania frequency distribution – 2012-2017[61]



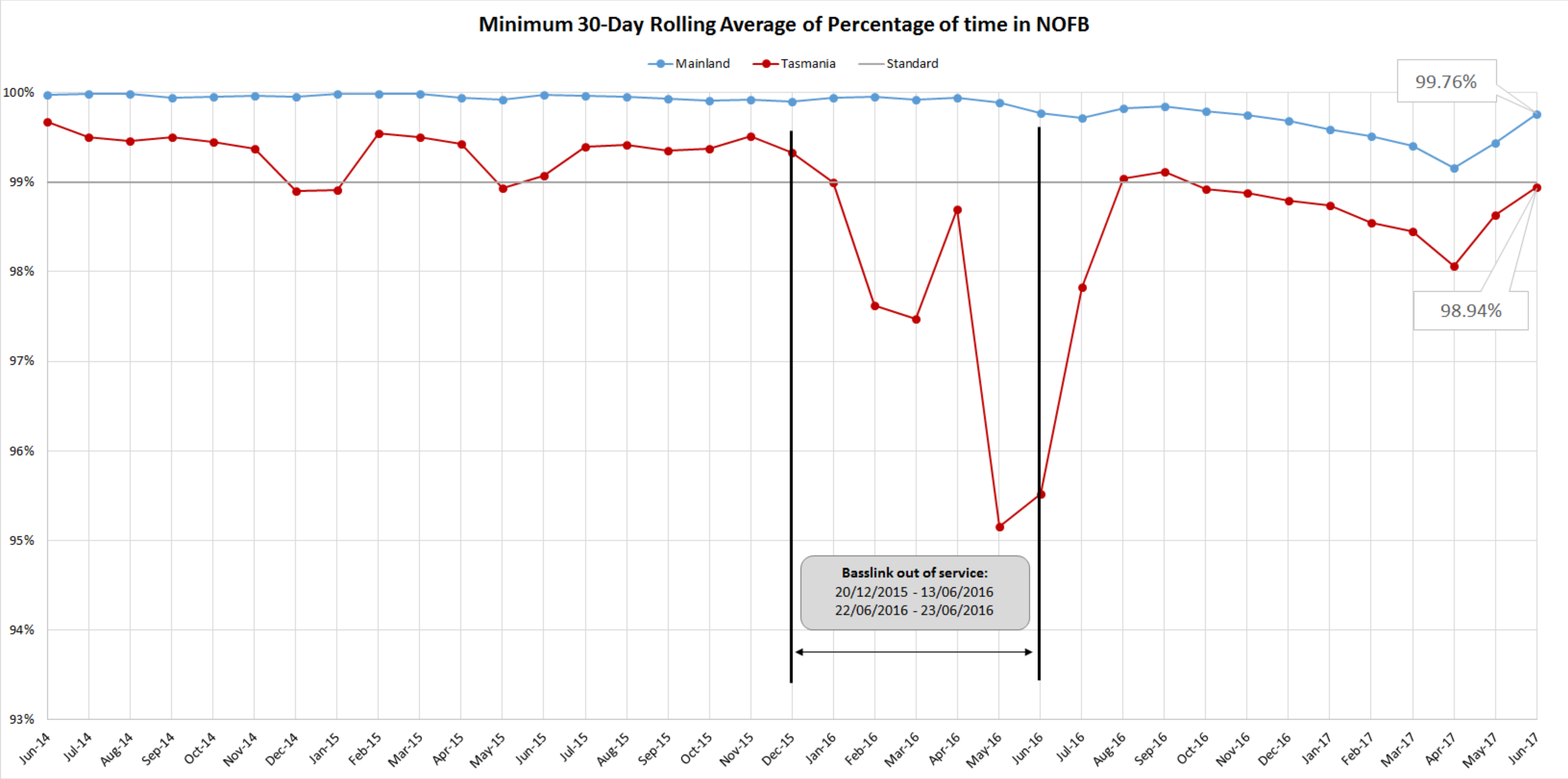
60 AEMO, 3 May 2017, ASTAG – Meeting Pack – 3 May 2017, Presentation 2 - Frequency Performance.

61 Ibid.

AEMO's most recent frequency monitoring report provides a more detailed picture of frequency performance in the NEM over the past three years, relative to the requirements of the frequency operating standard.[62] Figure 3.6 displays the performance of the NEM in terms of compliance with the requirement in the frequency operating standard that the power system frequency be maintained within the normal operating frequency band for 99 per cent of the time over any 30 day period.

62 AEMO has recently been producing these frequency reports voluntarily on an ad hoc basis. However, between 2011 and 2014, AEMO published frequency and time deviation monitoring reports on a quarterly basis. The issue of frequency monitoring and reporting is addressed further in section 5.2.6.

Figure 3.6 NEM mainland and Tasmanian frequency performance[63]



63 AEMO 2017, Frequency monitoring – Three year historical trends, 9 August 2017.

This report shows a decline in frequency performance in both the mainland and Tasmania from September 2016 through to April 2017, followed by an improvement in frequency performance in May and June 2017. The AEMO report states that the degradation of frequency performance during early 2017 was related to settings within AEMO's AGC system which were subsequently changed to correct the frequency performance. These changes are likely to have contributed to the improvement in frequency performance seen since April 2017. AEMO's commentary on this is included in full in Box 3.2.[64]

Additional frequency performance data is included in appendix A, which shows an increased incidence of exceedance events (where the power system frequency falls outside the normal operating frequency band) for both the NEM mainland and Tasmania in recent times.

Box 3.2 Excerpt from AEMO frequency monitoring report – August 2017

"The mainland frequency was within the normal operating frequency band more than 99% of the time over any 30-day period from June 2014 to June 2017, as required by the frequency operating standard. However, the Tasmanian frequency did not meet the standard at all times, notably during the following two extended periods:

- January 2016 to July 2016 – the Basslink interconnector was out of service from 20 December 2015 to 13 June 2016, and this coincided with low dam water levels and drought conditions in Tasmania. Initially, fast FCAS was provided by hydro generators. From 29 December 2015 onwards, fast FCAS was no longer sourced from the market in order to improve the operational efficiency of hydro generators and conserve water. Instead fast FCAS was provided by a generator tripping scheme and a temporary adaptive under-frequency load shedding scheme. Also temporary diesel units were brought online to augment the reduced hydro generation during this time. Several factors contributed to the frequency in Tasmania being within the normal operating frequency band for less than 99% of the time in a 30 day period.

— Loss of support from the mainland to manage frequency due to the Basslink outage.

— Reduction in FCAS provided by governor droop control.

— Detuning of the AGC system.

— During this period, sustained frequency oscillations were

64 AEMO 2017, Frequency monitoring – Three year historical trends, 9 August 2017, p. 4.

observed in Tasmania, and investigations showed that the AGC participated in these oscillations. However, it was not determined if the AGC caused the oscillations. The AGC was detuned by reducing certain gains to resolve the problem, which made the AGC less responsive to frequency deviations.

- October 2016 to June 2017 – AEMO investigated the gradual decline in frequency performance and identified that times of prolonged frequency deviations coincided with a large portion of regulation FCAS enabled in Tasmania. During these times, the AGC system at AEMO was not able to dispatch the full enablement in Tasmania due to its detuned configuration at the time. On 1 May 2017, AEMO constrained the regulation FCAS from Tasmania to the mainland to 34 MW to ensure that the NEM dispatch engine (NEMDE) only enabled regulation FCAS in Tasmania to the extent that the AGC system could dispatch it under the existing configuration. On 5 May 2017, the AGC gains were increased such that up to 50 MW of regulation enabled in Tasmania by NEMDE could be successfully dispatched by the AGC. These changes have contributed to an improvement during May and June 2017. However, more data over a longer period will be required to properly assess the impact. AEMO is further investigating possible changes to the AGC and will review the current configuration when more data is available."

In February 2017, as part of its Future Power System Security work program, AEMO convened the Ancillary Services Technical Advisory Group (AS-TAG), which brings together technical experts from the power industry to investigate solutions for current and future issues relating to ancillary services and power system security. To inform the work of this group, AEMO engaged DIgSILENT in May 2017 to investigate and report on the likely causes of the degradation of frequency regulation in the normal operating frequency band, and report on the materiality and potential consequences of this.

DIgSILENT's findings

Evidence

The preliminary results of the DIgSILENT analysis were presented to the AS-TAG on 9 August 2017. AEMO published the report itself on 21 October 2017.

The Commission understands that the DIgSILENT analysis confirmed that the root cause of the long term degradation of frequency performance is a reduction of primary frequency response within the NEM during normal operation.

DIgSILENT's analysis shows that there has been a very significant decline in the amount of governor response being provided within the normal operating frequency band since the introduction of the FCAS markets and the removal of the compulsory provision of governor response. It concludes that this has had an adverse impact on the performance of frequency regulation within the normal operating frequency band.[65]

This reduction of primary frequency response during normal operation is understood to have taken place gradually over a period of years through generators putting in place changes to their generator control systems including:[66]

- Widening their governor dead band settings out to between ±0.1 Hz and ±0.15 Hz. The effect of this is that the generators that have made this change are unresponsive to frequency changes until the frequency drops below 49.9 Hz – 49.85 Hz or rises above 50.1 – 50.15 Hz.

- Upgrading of older mechanical governors to newer digital control systems. These digital governor control systems enable a generator to easily change the frequency response mode of the generator, and the governor settings such as the dead band and droop characteristics.

- Where it is more difficult or costly to change their governor settings and uneconomic to upgrade to digital systems, generators have installed secondary control systems to dampen the primary governor response of their generating units, in favour of maintaining alignment of generator output with dispatch targets. These secondary controllers essentially expand the effective dead band for these generating units to ±0.15 Hz, in line with the normal operating frequency band of 49.85 Hz to 50.15 Hz.

The net result of these changes to generator control systems is a reduction in the level of primary frequency control that contributes to maintaining the power system frequency within the normal operating frequency band (49.85 Hz to 50.15 Hz).

The DIgSILENT report noted that AEMO's AGC system is not designed to be able to make up for the reduction in primary frequency control.[67] The Commission understands that the AGC system is capable of responding to generation and demand imbalance within approximately 30 seconds whereas primary frequency control is able to respond almost immediately to frequency deviations based on local frequency measurement and automatic response through the generator governor control systems.

DIgSILENT also reported on its preliminary assessment of a small number of slow unstable frequency oscillations that have occurred recently within the NEM power

65 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, p. 6.

66 Ibid., pp 29, 42.

67 The AGC is designed as a secondary frequency control system that centrally measures the power system frequency and sends out "raise" or "lower" signals to the registered generators and loads that are dispatched to provide FCAS to correct the small frequency deviations.

system.[68] DIgSILENT confirmed the occurrence of two oscillatory events, one on 28 October 2016 and the other on 10 February 2017. The event on 10 February 2017 followed the failure of a generating unit at the Tallawara power station. The event on 28 October 2016 was not associated with any identified contingency event. Both events showed oscillations of frequency with a wave period of approximately 25 seconds that persisted for between 5 and 10 minutes. DIgSILENT noted that "further work would be required to examine the oscillatory events in detail to ascertain their cause or causes."[69]

Consequences of deteriorating frequency control performance

DIgSILENT identified a number of consequences of deteriorating frequency control performance, including:

- increased wear and tear on plant due to excessive movement caused by frequency deviations
- reduction in the efficiency of generators due to changes in output as result of deteriorating frequency regulation and governor response
- reduction in system security for contingencies that result in significant changes in transfer across interconnectors
- increase in regulating FCAS costs
- possibility of further withdrawal of primary frequency control due to the added burden on existing primary frequency control.[70]

Possible causes of the deterioration

DIgSILENT identified a number of drivers that are contributing to the decline in primary frequency control within the NEM including:

- Generators who provide primary frequency control incur increased fuel and maintenance costs as a result of this mode of operation. As this service is not mandatory, nor are the costs reimbursed, there is no incentive for generators to provide primary frequency control.
- Many market participants believe that their causer pays factors can be reduced when their generator governors are set up to be unresponsive to frequency.[71]

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68 These oscillatory event were identified by Pacific Hydro and reported in the Paciifc Hydro submission to the Independent Review into the Future Security of the National Electricity Market, March 2017.

69 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, pp. 34-35, 47.

70 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, p. 47.

- Some market participants noted compliance with their rules obligations was more difficult if they operated with governors that responded to frequency changes. This includes compliance with dispatch targets, compliance with FCAS offers and compliance with generator performance standards. This is discussed further in the next section.

The DIgSILENT analysis identified a number of other contributing factors to the degradation in frequency performance in the NEM, including:

- An increase in contrary frequency control behaviour.

  Contrary frequency control has been found to occur due to a number of situations where the AGC instruction to generators may run contrary to the recovery of a frequency deviation. For example where the frequency is above 50 Hz and the AGC system is sending out "raise" signals to generators enabled to provide regulating FCAS. One of the causes of this phenomenon is time error correction, which is used to reduce accumulated time error that builds up due to deviations in the power system frequency. The frequency operating standard includes a limit on the maximum amount of accumulated time error which is being reviewed by the Reliability Panel through the *Review of the frequency operating standard*.[72]

- A reduction in load frequency response due to the increase of industrial loads supplied by variable speed drives. The power demand of these machines is independent of system frequency due to the fact that they are connected to the power system behind electronic inverters rather than traditional "direct on-line" connection.[73]

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71 Causer pays is the mechanism by which AEMO recovers the cost of regulation FCAS services from Market Participants. Regulation services costs are allocated to Market Generators and Loads on the basis of their contribution factors calculated over a period of a month. These factors reflect the degree to which the generators actual output or, in the case of a scheduled load, their actual demand, differ from the targets assigned by the NEMDE. A further discussion of causer pays arrangements is set out in section 5.2.5.

72 Historically, certain clocks operated as synchronous machines, relying on an accurate power system frequency in order to measure time accurately. For such synchronous clocks, frequency deviations away from the nominal power system frequency of 50 hertz resulted in incorrect time keeping, or an "an accumulated time error". In order to correct for this time error, AEMO has historically run the power system marginally faster (or slower) than the nominal frequency for a period of time to compensate for any accumulated time error. Synchronous clocks have largely been superseded by quartz crystal clocks and are no longer common, hence accumulated time error is no longer as relevant for accurate time keeping as it once was.

73 Load frequency response is a phenomena associated with the operation of synchronous motors where the power demand of the motor decreases due to a drop in system frequency and conversely the power demand increases in response to an increase in system frequency. This helps to stabilize system frequency changes by acting to balance supply and demand in the power system. Inverter connected machines, such as those connected via variable speed drives, do not necessarily have this operational characteristic and are more likely to have demands that are unresponsive to frequency, unless they are expressly programmed to be responsive to system frequency.

- A reduction in system inertia in the NEM due to the increase of inverter supplied generation, such as wind power and solar PV, and the retirement of aging large thermal generating units. This issue is the subject of the *Managing the rate of change of power system frequency* and *Inertia ancillary service market* rule changes and will also be considered as part of this review.[74] Further detail on these considerations is set out in chapter 6.

Further evidence and analysis of these issues, including the DIgSILENT findings and the question of whether a mandatory response obligation should be re-introduced to address these issues, is discussed in chapter 5.

Question 2	**Drivers of degradation of frequency performance in the NEM**
(a)	**Do stakeholders agree with the drivers of the observed long term degradation of frequency performance as identified by DIgSILENT?**
(b)	**Are there any other drivers of frequency degradation in the NEM that are not mentioned here?**

Interaction between compliance with dispatch instructions and frequency control

The Commission is aware that there is a perception that recent AER decisions relating to compliance with dispatch instructions have played a role in generators preference to widen their governor dead bands. In a submission to the AEMC's *System security market frameworks review*, Pacific Hydro referenced the CS Energy undertaking and suggested that some generating units in the NEM that have historically provided fast acting services to increase their output in proportion to frequency deviations have "progressively detuned their controls so that they are not found to be non-compliant with their dispatch instructions." Pacific Hydro noted that loss of governor droop control removes an important primary control action from the system.[75]

The DIgSILENT report suggests that there is a heightened awareness among generators of compliance with dispatch instructions and the operation of generator governors following the CS Energy undertaking, and a concern that the AER is not in favour of governor response being provided. It notes that the AER's emphasis on compliance with dispatch targets, and the fact that there is no rule requiring governor action from generators, may be contributing to the withdrawal of governor response in the NEM.

DIgSILENT also state that the AER's approach to enforcing compliance with dispatch instructions is informed by the assumption that effective market operation, in

74 See:
http://www.aemc.gov.au/Rule-Changes/Managing-the-rate-of-change-of-power-system-freque
http://www.aemc.gov.au/Rule-Changes/Inertia-Ancillary-Service-Market

75 Pacfic Hydro, Submission on *System Security Market Frameworks Review* interim report, 7 February 2017, pp. 8-9.

conjunction with the provision of regulating FCAS, is adequate to deliver frequency control in the NEM, and that compliance with dispatch instructions positively assists power system security, including frequency control.[76]

A summary of AER infringement notices issued to CS Energy on 4 July 2016 in relation to compliance with dispatch instructions is included in Box 3.3.

Box 3.3 Summary of AER infringement notice to CS Energy for failure to follow dispatch instructions - 4 July 2016

The NER requires registered participants to follow dispatch instructions issued by AEMO unless to do so would, in the participant's reasonable opinion, be a hazard to public safety or materially risk damaging equipment.[77] It also requires scheduled generators to ensure that the dispatch offers they submit to AEMO reflect, at all times, the capability of their generating units to generate power.[78]

AEMO relies on conformance with dispatch instructions to ensure that it can effectively perform its function as power system operator and market operator for the NEM. The AER monitors these requirements and can take enforcement action when appropriate.

In June 2016 the AER issued infringement notices to CS Energy, the registered participant responsible for the Wivenhoe and Gladstone Power Stations in Queensland, because it had reason to believe that CS Energy failed to comply with these clauses, specifically by:

- not following dispatch instructions issued to the Wivenhoe generating units, which over-generated by more than 200 MW on two occasions in February 2014
- not ensuring that, on 13 February 2014, certain scheduled generating units at the Gladstone Power Station could comply at all times with their dispatch offers.[79]

CS Energy paid an infringement penalty. It also put in place various measures to improve its compliance in this area and offered court-enforceable undertakings to continue to do so.

The enforceable undertaking sets out the factors that led or contributed to the non-compliance, including the governor response or "droop" characteristics at

76 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, Final report, 19 September 2017, pp. 26-27.

77 See clause 4.9.8(a) of the NER.

78 See clause 4.9.8(b) of the NER.

79 See: 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

the Gladstone power station. Governor response or “droop” describes when a generating unit inversely changes output level in proportion to system frequency. This characteristic may mean that a generating unit automatically departs from energy dispatch targets in response to system frequency deviations, notwithstanding that it has not been instructed by AEMO to provide regulating FCAS.

Governor response (droop) can be prevented by implementing a ‘dead band’ of system frequency either side of 50 Hz in which the generating unit will not respond to frequency deviations. The CS Energy undertaking notes that the dead band settings at Gladstone at the time meant that the units could not provide contingency FCAS when the dead bands were in. To allow CS Energy to offer contingency FCAS services, dead bands were not in place on the Gladstone scheduled generating units during certain dispatch intervals. As a result, in some of these dispatch intervals the units automatically changed load in proportion to their droop characteristic, contributing to the units generating output in excess of the relevant dispatch instruction.[80]

The undertaking notes that CS Energy will change its dead bands and use its best endeavours to ensure that the revised dead band settings at the Gladstone units are maintained, with the option of having no dead bands to only be used during emergency or legitimate testing situations. This reduces the Gladstone power station’s ability to respond to small frequency excursions.

AEMO's response to DIgSILENT findings

AEMO indicates that it will consider the findings in the DIgSILENT report when addressing future requirements for frequency control. This includes AEMO's ongoing consultations on the procedure for determining contribution factors (the "causer pays procedure"), which is used to allocate costs associated with regulation services to market participants who are determined to have contributed to frequency deviations.[81]

AEMO's review of the causer pays procedure commenced in December 2016 following the NEM Wholesale Consultative Forum in January 2016 where stakeholders expressed support for a review of this procedure to ensure that it remained appropriate and effective in the current power system. The issues paper for the *Causer pays procedure consultation* identified a number of areas for consideration through this consultation, including:[82]

- local requirements for FCAS

80 Undertaking to the AER by CS Energy Limited, 29 June 2016, p. 3.

81 https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Causer-Pays-Procedure-Consultation

82 AEMO, 2016, Causer pays procedure consultation, December 2016.

- treatment of positive performance that assists AEMO with controlling power system frequency
- the size and timing of the sample period for the determination of causer pays contribution factors.

The Commission understands that AEMO intends to publish a draft determination on the causer pays procedure consultation in November 2017.

3.1.5 Reduction in load frequency response due to increased uptake of inverter-based loads

Load frequency response refers to the natural reduction of power demand from some loads due to a reduction in power system frequency. This effect helps moderate the impact of any frequency deviation by lessening the supply/demand imbalance that causes the frequency change.

Load frequency response is typically provided by direct-connected induction motors. Inverter-connected motors and pumps do not necessarily provide this load frequency response.[83] The analysis by DIgSILENT identified a reduction in load frequency response as a contributing factor to the decline of frequency control performance in the NEM.[84] This reduction in load frequency response is attributed to a trend of older, direct-connected machines and appliances being replaced with newer, inverter-connected machines. Examples of this include:

- the use of variable speed drives for motors in industrial loads
- the increase of inverter-based residential appliances such air conditioners.

DIgSILENT's investigations indicate that the impact of this change may be slight at present but it is expected to grow over time.[85]

3.2 Greater potential for supply/demand imbalances

Some renewable energy generation technologies are by nature *variable*. Solar PV panels generate electricity when the sun shines. Wind generators generate electricity when the wind blows.

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83 As with inverter-connected generators such as wind turbines and solar PV, inverter-connected loads are connected to the power system through power electronic equipment that separates the electrical frequency of the device for that of the power system. As a result, such equipment does not naturally respond to changes in power system frequency as a direct-connected machine would do. It is possible to program inverter-connected machines to provide a frequency response, but this is not currently a default setting.

84 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, p. 26.

85 Ibid.

Some aspects of that variability are relatively predictable. For example, the output of solar PV panels will vary as the sun rises and sets. Other factors leading to variability can be relatively unpredictable. For example clouds covering a solar PV panel, or wind suddenly dropping, can potentially result in more rapid changes in power output. The predictability of changes in power output varies over time as well. For example, solar PV output can be considered to be relatively predictable on an average basis several months in advance. It is even possible to use weather technology to predict when clouds are moving across the sky, however, the exact timing of when a cloud moves across a particular panel may be difficult to predict.

Predictability of changes in power output has also been affected by technological developments, market and regulatory developments and innovation by demand-side management providers over the past decade. These developments have made it easier for consumers across all sectors (industrial, commercial and residential) to adapt their consumption patterns to manage and control their energy use, and, in turn, their expenditure. For example, home energy management systems can provide demand response and deliver load reductions in a way that goes largely unnoticed by the customer. However, these developments have implications for the management of the power system.

Load (or demand) forecasting has typically relied on the underlying diversity in consumer behaviour. Generally, not all appliances are used at the same time or in the same ways. However, the operation of new technologies (e.g. home management systems or batteries) may be less predictable for AEMO and NSPs, particularly if they are driven by proprietary algorithms.

This concept of predictability is important because it impacts the way that AEMO dispatches energy in the NEM to balance supply and demand, which has important implications for the frequency of the power system.

Generators in the NEM must be classified as either scheduled, semi-scheduled, or non-scheduled generators. Generally, a large generator (30 MW and over) that is capable of participating in the central dispatch process is classified as a scheduled generator, a large generator that has intermittent output (such as a wind or solar farm) is classified as a semi-scheduled generator, and a smaller generator (less than 30 MW) or a generator that is not capable of participating in AEMO's central dispatch process, is classified as a non-scheduled generator.[86]

Scheduled and semi-scheduled generators participate in AEMO's central dispatch process. In this process AEMO receives bids from scheduled and semi-scheduled generators and prepares a forecast of the demand and supply of all participants who are not scheduled (that is, semi-scheduled and non-scheduled generators). The forecast of demand currently includes forecasts of rooftop solar PV production, but not how aggregated home energy management systems or batteries will behave. An overview of the central dispatch process, including forecasting of variable supply

86 See clauses 2.2.2, 2.2.7(a) and 2.2.3 of the NER.

(non-scheduled and semi-scheduled generation) and variable load (rooftop solar PV) is provided in AEMO's Visibility of distributed energy resources report.[87]

AEMO dispatches capacity in the market every five-minutes to balance supply and demand in the NEM in real-time. Generators specify in their bids their ability to ramp up or down to meet new targets set by AEMO. AEMO's dispatch instructions to scheduled generators take into account the 'ramp rates' they are able to achieve. AEMO can limit a semi-scheduled generator's output in response to network constraints or because it is out of merit in the dispatch process, but at other times the generator can supply up to its maximum registered capacity.

With changes in output from semi-scheduled and non-scheduled generators or behind the meter rooftop solar PV as well as changes in demand due to the operation of home energy management systems or batteries (together 'non-dispatchable capacity'), scheduled generation sources are required to "ramp up" or "ramp down" so that supply matches demand in real time. When supply and demand match, the frequency on the power system is stable. This gives rise to two issues explored in this chapter:

- an increased need for ramping to meet rapid aggregate changes in output from non-dispatchable capacity as the sun rises and sets - referred to in this paper as 'daily ramping requirements'
- an increased need for ramping to respond to sudden changes in output from non-dispatchable sources of supply due to changing weather conditions, and demand (i.e. battery storage and home energy management systems) due to changes in their operation - referred to in this paper as 'rapid ramping requirements'.

The scope of this review includes, but is not limited to, assessing whether existing frequency control arrangements will remain fit for purpose in light of likely increased ramping requirements. Within this scope, this chapter will discuss both of the issues noted above.

3.2.1 Daily ramping requirements

As part of its 2016 *National transmission network development plan* AEMO identified a range of emerging challenges for transmission networks.[88] One emerging challenge it examined is the impacts over time of changes in non-dispatchable capacity over the course of the day.[89] It shows that scheduled generation, such as coal, gas, hydro and grid scale battery power, is needed to ramp up and down to balance supply with demand as the output of non-dispatchable capacity changes through the day. Over time, as more non-dispatchable capacity enters the market, the need for ramping from scheduled generation increases. If there is not enough scheduled generation available

87 AEMO, *Visibility of distributed energy resources*, January 2017, p. 27.

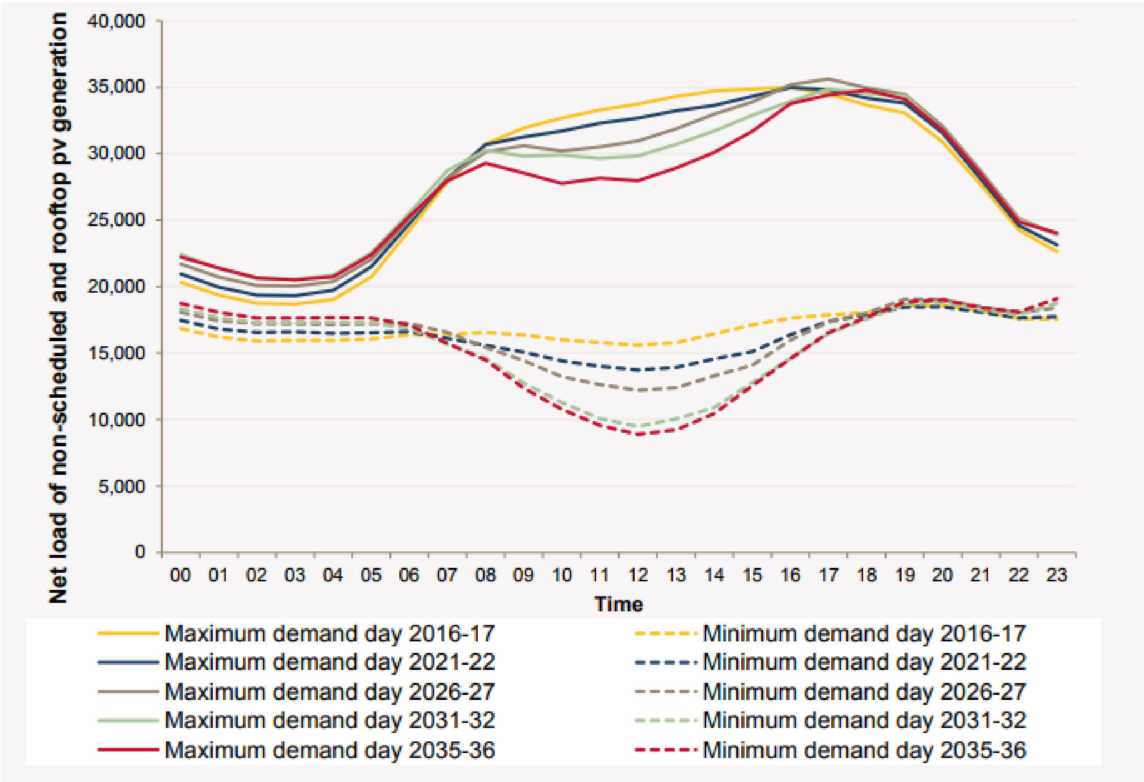
88 See Chapter four in AEMO, *National transmission network development plan*, December 2016.

89 Ibid, p. 72.

to ramp up or down to meet demand throughout the day, a resulting mismatch in supply and demand may affect the frequency of the power system.

Based on a best assessment of demand, assuming a neutral economic outlook, AEMO projected NEM-wide scheduled generation requirements on maximum and minimum demand days.[90] Over the period to 2035-36 AEMO projects there will be an increased need for scheduled generation to ramp up to meet evening peak demand, and a declining need for generation to ramp up to meet morning peak demand. This is shown in Figure 3.7 below.

Figure 3.7 Projected NEM-wide demand excluding non-dispatchable capacity (MW)

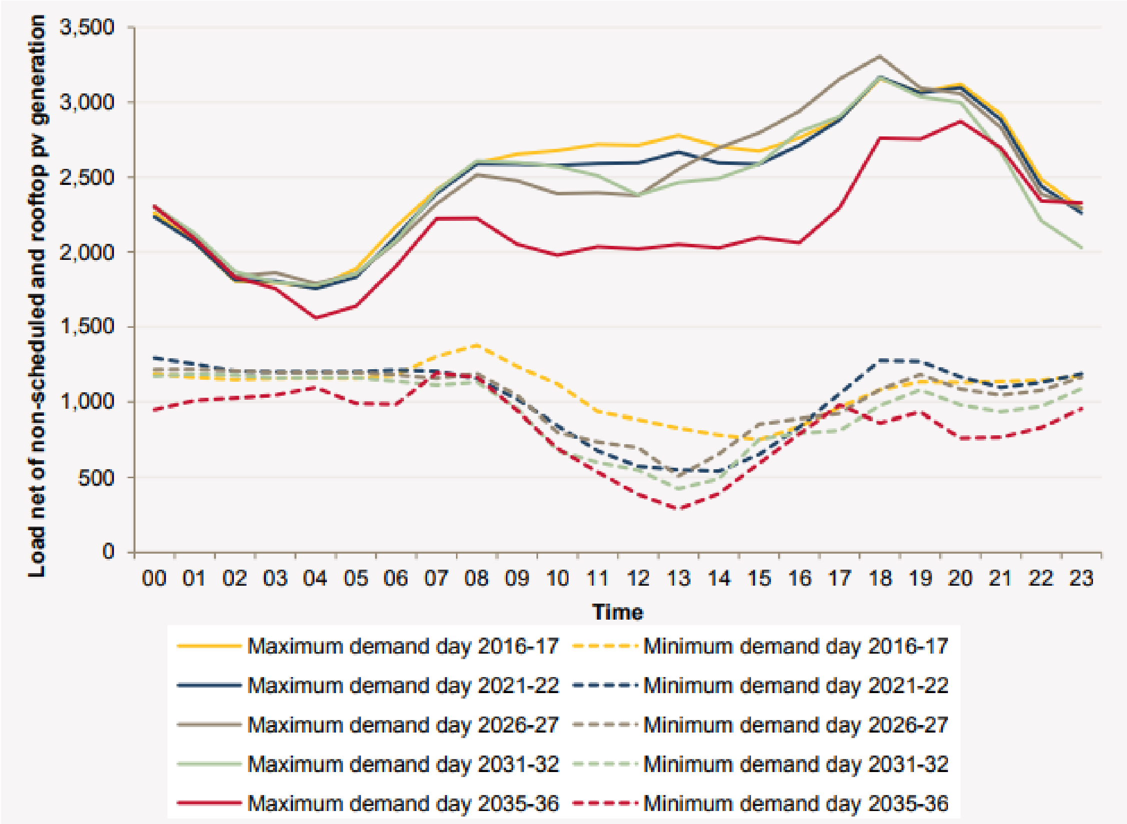


Different jurisdictions are projected to have different levels of non-dispatchable capacity in their region, resulting in different ramping needs for scheduled generation. AEMO projects that the ramping required of scheduled generation will be more pronounced in South Australia than the NEM-wide average because of the higher than average penetration of non-dispatchable capacity in that state.[91] This is shown in Figure 3.8 below.

90 Ibid, p. 72.

91 Ibid, p. 73.

Figure 3.8 **Projected South Australian demand excluding non-dispatchable capacity (MW)**



This is often referred to as the "duck curve" given the distinctive shape arising from the increasingly deep belly of the curve (projected minimum demand) relative to the back (projected maximum demand). This phenomenon is a key driver of increased ramping requirements. While it is not within the scope of the review to propose solutions that help reshape demand profiles, the review will discuss potential solutions to address changing requirements for frequency control that result from these changes.

The ability for scheduled generation to ramp throughout the day to meet changing residual demand in a region (that is, demand less non-dispatchable capacity), and thus keep frequency balanced, is determined by the ramping capacity available in the region. This is made up of the ramping abilities of the scheduled generators available in the region, as well as the ramping capacity that is available through interconnection.

As part of its assessment of the *Five minute settlement rule change*,[92] the AEMC considered the ramping capacity of individual generating units, different types of generation, and the average levels of ramping available in each NEM region.[93] The analysis found there were significant ramping capabilities in the NEM, but that the mix of generation able to provide that ramping capacity differed by NEM region.

92 The *Draft National Electricity Amendment (Five Minute Settlement) Rule 2017* was published on19 May 2017.

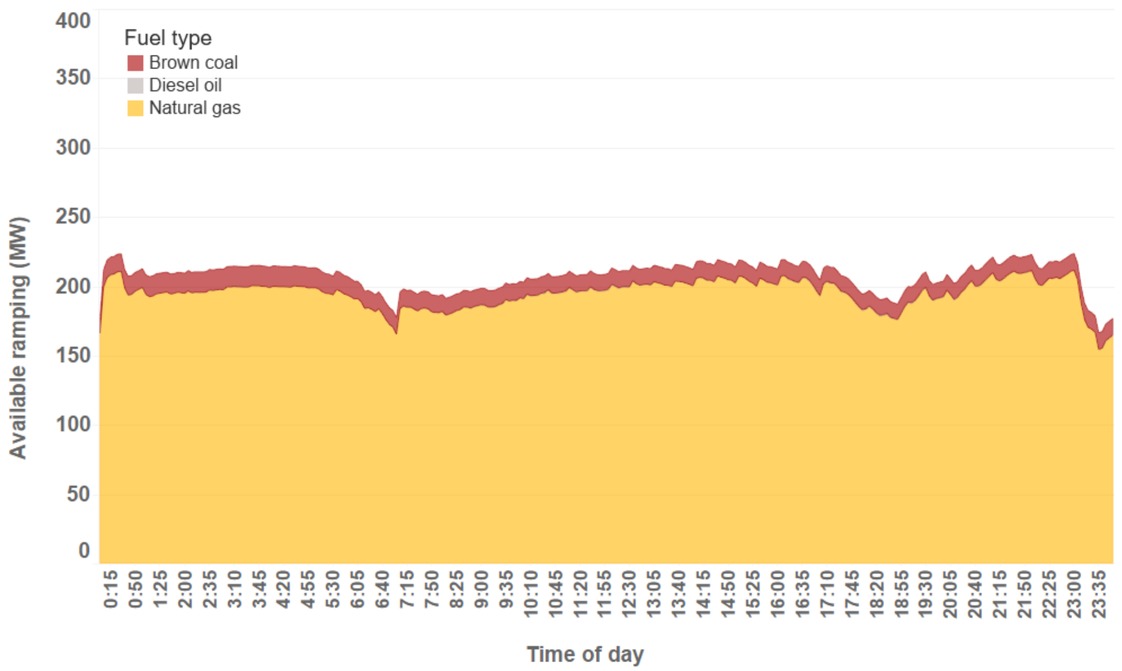
93 See AEMC, *Five minute settlement: directions paper*, April 2017, pp. 42- 49.

The aggregate, regional ramping capability was calculated for every five minute period in 2016, then averaged for each five minute period of the day.[94] This analysis used data from the changes in the dispatch targets of scheduled generating units from one dispatch interval to the next. In each dispatch interval, each unit's ramping potential was calculated as the lesser of:

- its maximum ramp rate and its available, unused generation, or
- if the unit was not generating at that time, zero.

Figure 3.9 and Figure 3.10 below show the total average additional generation capacity available from already scheduled generators for a given 5 minute dispatch interval, compared to the previous interval, in South Australia and NSW respectively. That is, they show the additional 'headroom' available to increase (ramp) generation over a period of 5 minutes. Note this does not include ramping capacity available through interconnection.

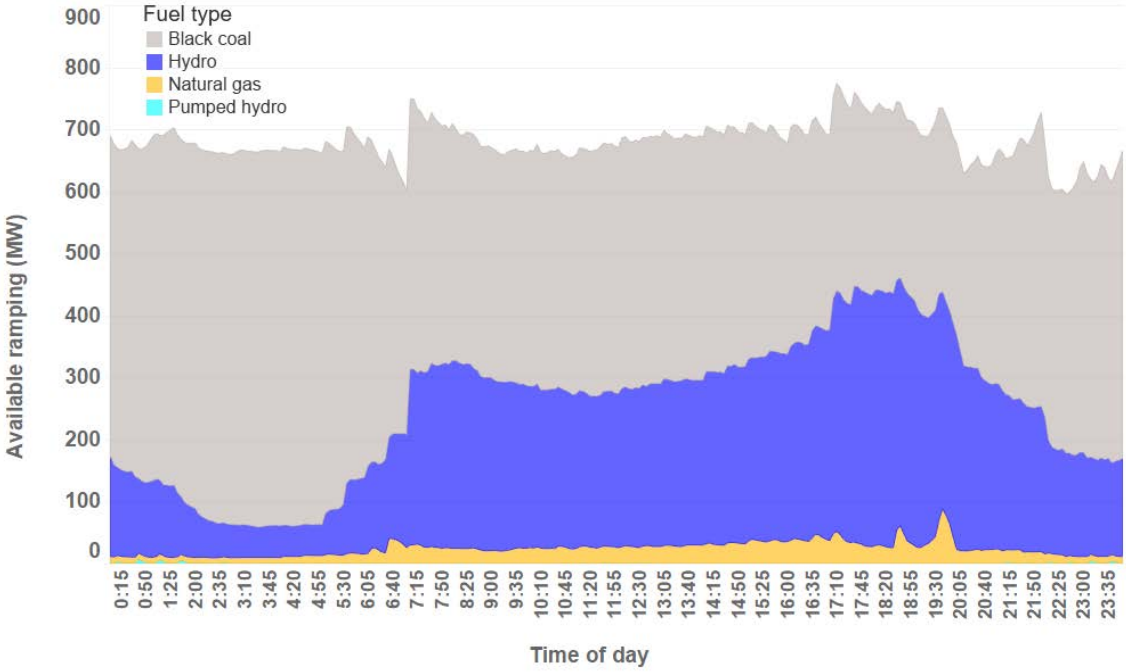
Figure 3.9 Ramping capacity in South Australia in 2016



The ramping capacity available in South Australia throughout 2016 was largely provided by gas generation, with some contribution from brown coal generation. By contrast, the ramping capacity available in NSW throughout 2016 was largely provided overnight by black coal generation and small amounts of hydro, gas and pumped hydro generation. During the day, ramping capacity was generally provided by black coal and hydro together, with some contribution from gas generation.

94 Ibid, p. 47.

Figure 3.10 Ramping capacity in New South Wales in 2016



For any five-minute dispatch interval throughout the day, the average ramping capacity available to be dispatched is substantial when compared with the average ramping needs expected out to 2035-36. This analysis does not tell us whether there are "outlier" five minute periods during the course of the year where very little ramping capability is available, and whether any such periods are likely to coincide with times that high rates of ramping are required to meet demand.

The aggregate reduction in output from non-dispatchable capacity at certain times of the day occurs over a time frame that is greater than individual five minute dispatch intervals. The availability of ramping capacity to meet changes in demand throughout the day (that is, outside of the five minute dispatch interval timeframe) is largely driven by the market frameworks supporting reliability, such as the contract and wholesale markets, the reliability price settings in the spot market (which are set with reference to the reliability standard), the information that AEMO provides to the market as well as external factors, such as the influence of emissions policy. The combination of these factors should signal to generators (and potential new entrants) the value of their capacity to meet demand as it changes throughout the day. This process should determine the availability of scheduled generation that is able to ramp up or down to meet demand and be dispatched accordingly by AEMO.

The more relevant aspects of ramping for the purposes of this review are the changes in non-dispatchable capacity on shorter time scales, within the five minute dispatch interval. These more rapid changes could influence the need for capacity to manage frequency through FCAS or other frequency control frameworks. These issues are discussed in the next section. FCAS market arrangements are more generally discussed in chapter 6.

3.2.2 Rapid ramping requirements

To balance supply and demand, AEMO dispatches scheduled generation to meet its forecast demand. In forecasting demand, AEMO takes into account the expected generation from semi-scheduled, non-scheduled and rooftop solar PV generation. Forecasting the levels of scheduled generation to dispatch may become more difficult with higher proportions of non-dispatchable capacity in the market. This could potentially increase the overall levels of uncertainty in the dispatch process, which may influence requirements for balancing services to maintain frequency within the frequency operating standard.

This section explores the potential power system frequency impacts of the short term variability in power output and short-term variability from non-dispatchable capacity. It also explores the existing tools to deal with those impacts and whether those tools are adequate for the future needs of the power system.

Short term variability of wind and solar generation

The task of balancing supply and demand could become more difficult with larger penetrations of non-dispatchable capacity because of the need to predict their output within five minute dispatch intervals.

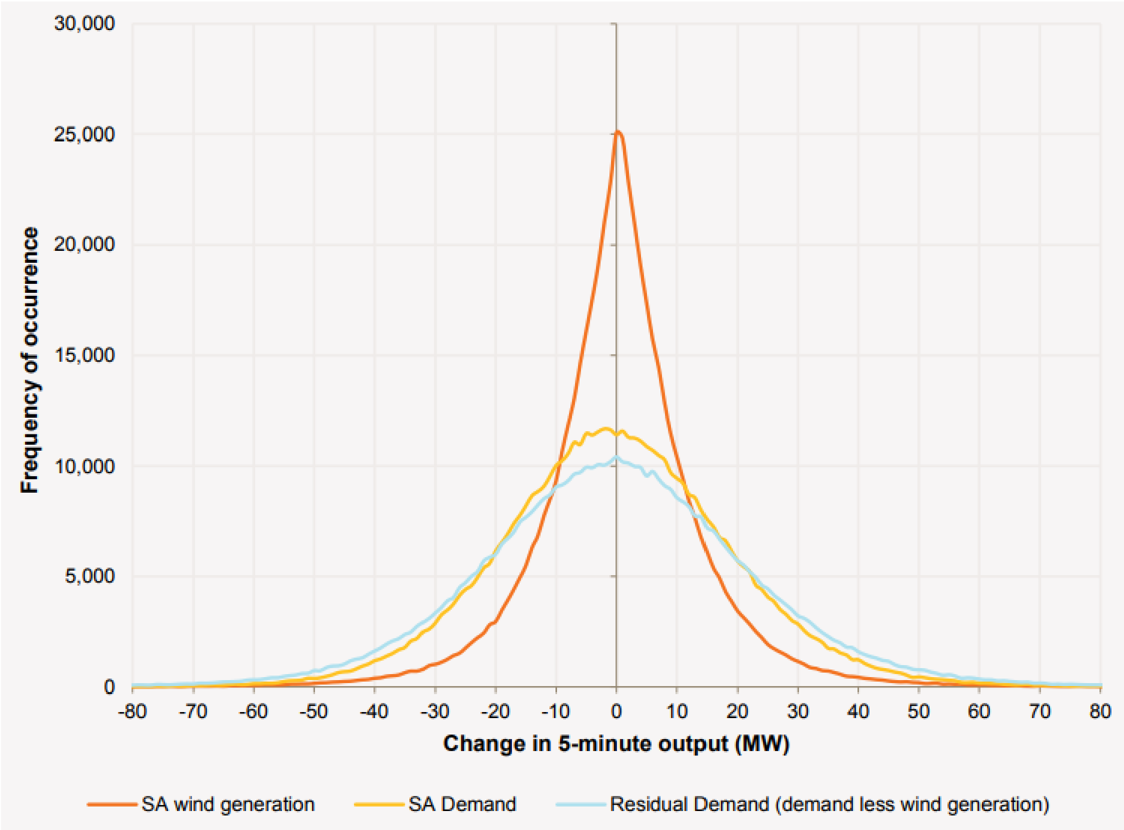
The *South Australian wind study report*, prepared by AEMO, considered the impacts of the variability of utility scale wind generation in South Australia.[95] The report analysed the changes in total output of wind generation in South Australia over five minute periods from 2010-11 to 2014-15. It also considered the variations in total demand and residual demand (demand less wind generation) over five minute periods.

The analysis shows that for 90 per cent of the time, South Australian total wind generation varied by no more than 24 MW, or 1.6 per cent of registered capacity.[96] It also shows that the wind generation in South Australia had the effect of increasing the number of variations in residual demand by more than 20 MW in a five minute period. Residual demand is important because changes in residual demand reflect the level of scheduled generation that is needed to ramp up or down to balance supply with demand. Residual demand is shown as the blue line in Figure 3.11 below.

95 AEMO, South Australian wind study report, October 2015, pp. 25-29.

96 Ibid, p. 27.

Figure 3.11 Variability of wind generation and residual demand in South Australia within five minutes (2010-11 to 2014-15)



AEMO's study also considered the variability of residual demand between 2010-11 and 2014-15.[97] It found that, over time, the number of variations in residual demand that are greater than 30 MW has increased slightly.[98]

The variability of individual wind farms was not considered in the *South Australian wind study report*. It was noted that aggregation was required to allow for the effects of smoothing, where the variations on output from individual wind farms may be offset by nearby wind farms.[99]

The study considered the variability of wind generation by regions within South Australia, including the mid-north area, the south-east area and the coastal peninsula area. The analysis considered the variability of wind generation within five and ten minute periods for each of these regions, as well as the total variability for South Australia.[100] The results are shown in Figure 3.12 below. Variability is expressed as a proportion of registered capacity and includes a range for each region, as well as the median and mean results.

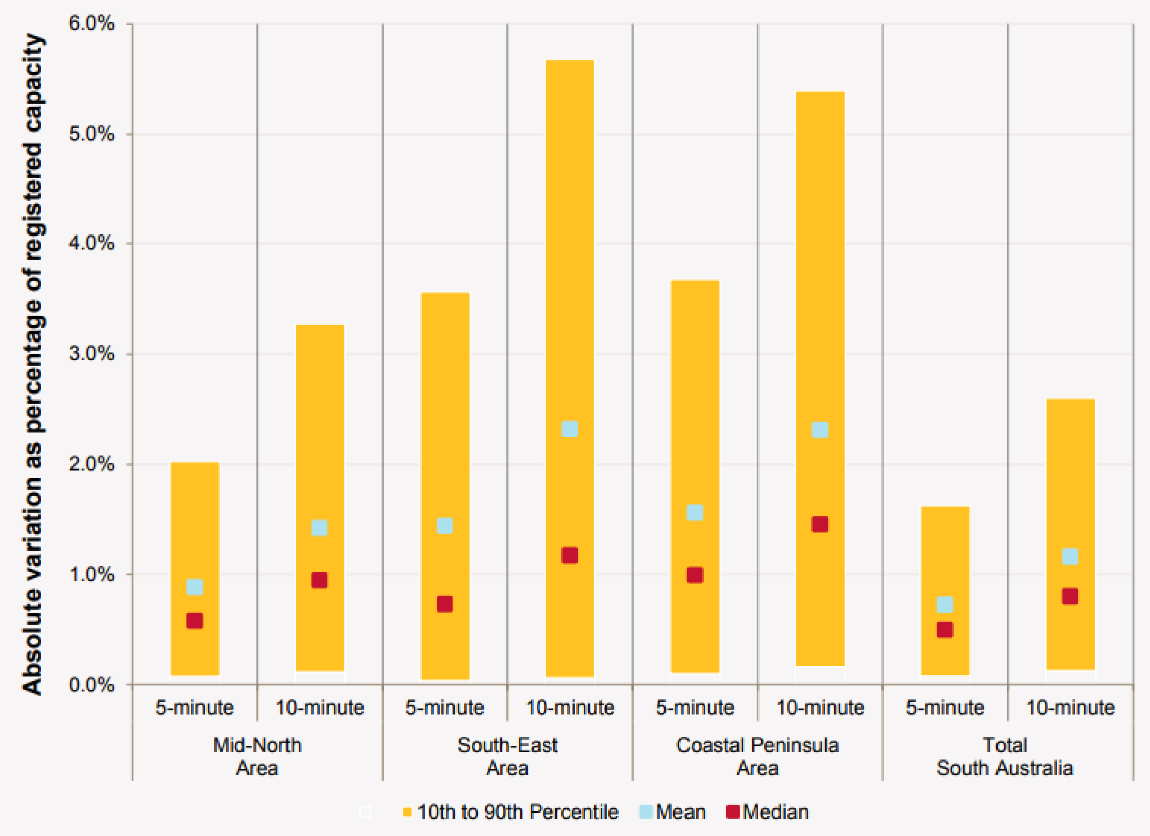
97 Ibid, p. 26.

98 Ibid.

99 Ibid, p. 27.

100 Ibid.

Figure 3.12 Variability of wind generation by region in South Australia



The analysis shows that as well as smoothing across wind farms in the same region, there is also a smoothing effect across all of South Australian wind generation. AEMO concludes that when aggregated across South Australia the variability of wind farms reduces when compared with individual areas, indicating that greater geographical diversity in wind generation leads to lower absolute variability.[101]

Similar analysis has not been conducted for large scale solar PV, but it is reasonable to expect that the smoothing effect of geographical diversity would also apply. It is also reasonable to expect that diversity in technology type would have a similar smoothing effect.

Diversity may therefore lessen the overall variability of non-dispatchable capacity from what was expected during a five minute dispatch interval. Regardless, it appears that overall an increased amount of non-dispatchable generation will result in some cases of relatively high variations in output that could potentially create imbalances in supply and demand, and so affect frequency.

The analysis presented above considers the number and scale of variations in wind generation output and residual demand. These variations will not trigger a need for frequency measures (such as regulating FCAS) to be used, unless the variations were not expected and scheduled generation was not dispatched accordingly to meet demand.

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101 Ibid, p. 28.

For example, AEMO may forecast that wind generation in a region will decrease by 20 MW over the course of a five minute dispatch interval. NEMDE, AEMO's dispatch engine, will then give scheduled generators dispatch instructions to ramp up to meet demand, accounting for the expected reduction in wind generation. If the wind generation in the region falls by the expected 20 MW, there should be no impacts on the frequency of the power system. However, if the wind generation varies materially from the expected 20 MW reduction, a mismatch will occur (unless offset by smoothing) that may influence the frequency of the power system, potentially triggering a need for regulating FCAS to bring the frequency of the system back to normal operating levels.

It is therefore not the variability of non-dispatchable capacity that creates an imbalance in supply and demand, but the variation in actual output or load from the forecast output or load within the five minute dispatch interval that creates the imbalance and subsequent impact on frequency.

AEMO is required to prepare forecasts of the available capacity of each semi-scheduled generating unit for the purposes of projected assessment of system adequacy (PASA), dispatch and pre-dispatch.[102] AEMO has developed a wind energy forecasting system that forecasts large scale wind generation, AWEFS, and a solar energy forecasting system that forecasts large scale and rooftop solar PV generation, ASEFS.[103] A detailed explanation of AWEFS and ASEFS is provided in the AEMC's *Reliability frameworks review* issues paper.[104]

The Reliability Panel's 2016 *Annual market performance review* assessed the accuracy of AEMO's forecasting of wind generation.[105] The results show an average variance of at or less than one per cent of forecast five minute output from actual output for each month in the period 2015-16. Figure 3.13 below shows the normalised mean variances for a range of time horizons from five minutes to six days ahead.

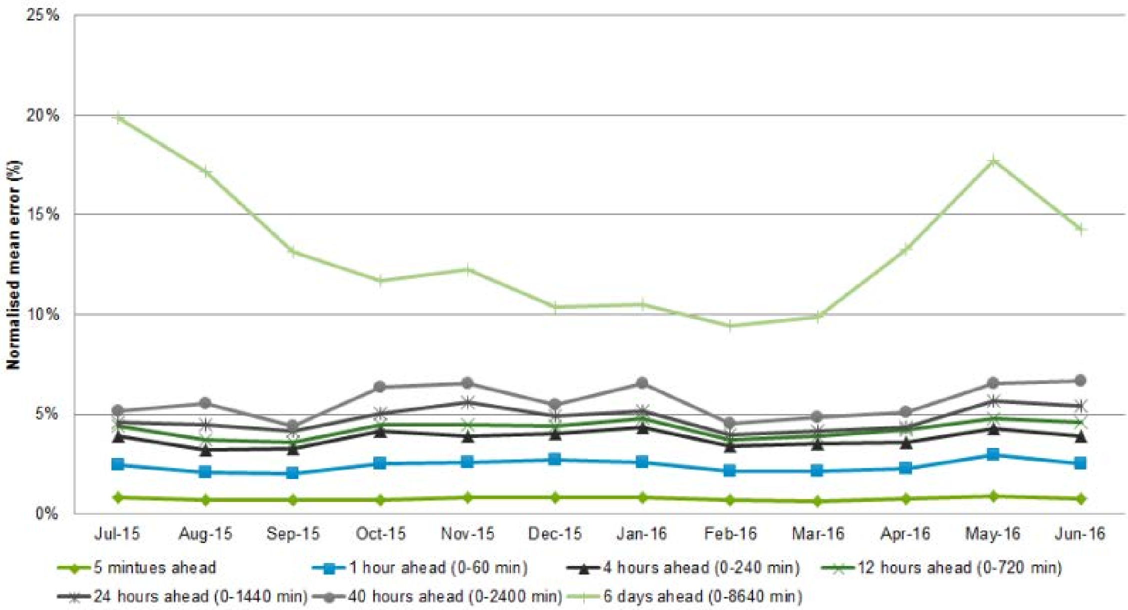
102 See clause 3.7B, NER.

103 AWEFS was implemented in two stages between 2008 and 2010 and ASEFS was implemented in two stages in 2014 and 2016.

104 AEMC, Reliability frameworks review: issues paper, August 2017, p. 46.

105 AEMC, *Annual market performance review: 2016*, May 2017, p. 102.

Figure 3.13 NEM-wide variations between forecast and actual wind output



When taken together, the analysis above shows that at times there will be variations in the output of non-dispatchable capacity between one five minute dispatch interval and the next. It also shows that AEMO forecasts these variations for, among other purposes, determining its dispatch instructions to scheduled generators to meet demand. A mismatch in supply and demand leading to an impact on the frequency of the power system should only occur where there is a difference between the forecast variation in the output of non-dispatchable capacity over the five minute dispatch interval, and the actual output of that capacity across the same period. As noted above, the NEM-wide average variation between forecast and actual wind generation is relatively low at or below one per cent. As a result, even if wind generation falls by 100 MW across a region, the difference between actual and forecast generation may on average be as little as 1 MW.

These effects may be more significant by region or sub-region when taking into account the reverse effect of smoothing across the NEM. They may also be less significant taking into account smoothing across different technology types (solar and wind) within the region. However, relevant to this point is that there is no published data available on the variation between forecast and actual large-scale solar generation or rooftop solar PV within five minute intervals in the NEM.

AEMO does not currently forecast changes in demand due to the operation of home energy management systems or batteries for the purposes of dispatch or pre-dispatch in the NEM as it is currently a relatively small factor influencing demand on the NEM. However, it is expected to grow. Over time, the operation of this capacity may have increasing implications for the supply and demand balance of the NEM within five minute dispatch intervals, and therefore impact frequency control frameworks.

AEMO is currently, or has recently considered, ways to improve its visibility of distributed energy resources. AEMO's demand-side participation guidelines will require registered participants to submit demand-side participation data annually at the national metering identifier level from April 2018. AEMO is also undertaking a range of work in the context of distributed energy resources and power system security, including its visibility of distributed energy resources project.[106]

The AEMC is seeking views on the materiality of the frequency impacts of the variability in non-dispatchable capacity within five minute dispatch intervals.

Question 3 Materiality of frequency impacts from non-dispatchable capacity

(a) What are the likely impacts on frequency of increasing proportions of non-dispatchable capacity, and reducing proportions of scheduled generation?

(b) Are there any significant impacts on frequency that may occur from changes in output from individual large scale semi-scheduled generation (large solar and wind farms)?

(c) Does the analysis for wind generation above hold true for large scale solar PV? Does large scale solar PV output change more rapidly than wind output? Are changes in solar output more difficult to forecast?

If a mismatch between the expected and actual output from non-dispatchable capacity occurs within the five minute dispatch interval, the existing mechanisms to control frequency on the power system are expected to address the mismatch. Section 6.3.2 below discusses the interaction between these existing frequency control frameworks and the variability of non-dispatchable capacity within five minute dispatch intervals.

3.2.3 Consumers changing how they use / produce electricity

An increasing amount of new energy technologies - such as rooftop solar PV, battery systems, electrical vehicles - is being connected to distribution networks by residential and small business consumers.[107] These technologies are greatly expanding the choices that consumers have to manage their energy needs, and changing the way in which these consumers draw electricity from, and export electricity to, the broader power system.

These changes are presenting challenges for AEMO in managing power system security. Distributed energy resources are not centrally dispatched by AEMO and are not subject to the technical parameters in the NER that registered participants are, such

106 See AEMO, *Visibility of distributed energy resources*, January 2017.

107 The Electric Vehicle Council of Australia estimates there were 1,369 sales of plug-in hybrid and fully electric vehicles in Australia in 2016, a fall of 23 per cent from 2015 and representing 0.1 per cent of the total Australian market . Electric vehicles available on the market in Australia do not currently have the capability to discharge into the grid (often referred to as vehicle-to-grid capability). See: Electric Vehicle Council (2017), *The state of electric vehicles in Australia* , available at www.electricvehiclecouncil.com.au.

as performance standards. As a result, AEMO has no direct levers to control the operation of these systems to maintain power system security. AEMO, through its Future Power System Security program, is considering new ways to forecast and manage the way that consumers with new energy technologies use the grid so that it can maintain power system security. We therefore propose to exclude this issue from the scope of the *Frequency control frameworks review*.

However, distributed energy resources also have the potential to support power system security, for example by providing services such as frequency response and voltage control. The potential for this to occur has been recognised by AEMO, the AEMC, Energy Networks Australia and the Finkel Panel,[108] but there has been no detailed consideration of how this could occur in a technical or regulatory sense. These issues are within the scope of this review and are discussed in more detail in chapter 7.

Question 4 Drivers of change

Are there other drivers of change affecting frequency control that are not set out in this section? If so, how material are they?

108 See: AEMO, Visibility of distributed energy resources, January 2017, p. 17; AEMC, Distribution market model, final report, p. 72; Energy Networks Australia / CSIRO, Electricity Network Transformation Roadmap, final report, April 2017, pp. 52-63; Commonwealth of Australia, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, pp. 62-63.

4 Assessment framework

This chapter sets out the AEMC's proposed assessment framework for undertaking the *Frequency control frameworks review*.

4.1 The national electricity objective

The overarching objective guiding the Commission's approach to this review is the national electricity objective (NEO). The Commission's assessment of any recommendations must consider whether the proposed recommendations promote the NEO. The NEO is set out in section 7 of the NEL, which states:

> "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:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

Based on a preliminary assessment of the issues raised by the review, the Commission considers that the relevant aspects of the NEO for further consideration are the efficient investment in, and operation of electricity with respect to the price and security of supply of electricity, as well as the safety and security of the national electricity system.

4.2 Trade-offs inherent in frequency control frameworks

Consistent with the relevant aspects of the NEO identified above, there is a requirement to consider that the achievement of higher levels of system security, through enhanced frequency control, is likely to entail a cost trade-off. It is possible that enhanced frequency control, delivered through a greater volume of ancillary services or stricter requirements on market participants, will involve an additional cost, which may increase the price of electricity to consumers. It is equally possible that optimising the design and implementation of FCAS markets may enable the delivery of enhanced frequency control at no additional cost or even with a cost reduction.

The key question for this review is therefore how to create frequency control (and associated services) frameworks that minimise the costs of achieving the frequency operating standard (consistent with the desired level of system security), given the emerging changes in the NEM and associated uncertainties.

Broadly, delivery options can be thought of as reflecting greater or lesser reliance on two principal approaches, namely:

- market-based mechanisms

- intervention mechanisms.

The existing frequency control framework, as set out in section 2.4, is largely market-based, but does have some elements of intervention intrinsic in its design, such as the terms and conditions of generator connection agreements and associated governor or inverter settings.

The Commission considers that intervention-based approaches, however well designed, are likely to be a second-best alternative to well-functioning markets at promoting economic efficiency in the long-term interests of consumers. Markets put consumers at the heart of decision making. Markets are generally the most efficient mechanism to further the interests of consumers through allowing efficient price discovery and production decisions based on competitive market dynamics, even where consumers do not directly participate (as is true for energy-related markets such as the NEM and FCAS markets).

By allocating risks to market participants, markets provide financial incentives to make efficient decisions and provide incentives for innovation, to the benefit of consumers.

Intervention-based approaches, on the other hand, tend to provide higher levels of certainty of a secure supply of energy. Such approaches are sometimes preferred when dealing with issues of system security because they tend to provide a higher level of confidence that the system can be maintained in a secure operating state for a wide range of conditions and circumstances.

Therefore, there are different costs and benefits for market-based or intervention-based approaches. Centralised control over security provides a high degree of certainty that a secure supply of electricity will be achieved. However, such an approach will likely foreclose the considerable potential benefits of a well-functioning market, imposing costs and risks on consumers. But, in some instances (for example, where security concerns are manifesting in operational time scales or where the risk external to the energy market prevents it from being well-functioning), intervention mechanisms are likely to be appropriate in order to maintain the integrity of the power system.

4.3 Principles

In order to articulate how the Commission will consider balancing the criteria outlined above, the Commission has set out a number of principles to guide the development of recommendations on potential changes to market and regulatory frameworks that affect security in the NEM. These principles will be used to guide the Commission's assessment of the existing frameworks, as well as any potential modifications to, or additional, mechanisms that will be considered through this review:

1. **Appropriate risk allocation:** Regulatory and market arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of providing a secure supply of electricity. Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Under a centralised planning arrangement,

risks are more likely to be borne by consumers. 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.

2. **Efficient investment in, and operation of, energy resources to promote a secure supply:** Any frequency control framework should result in efficient investment in, and operation of, energy resources to promote a secure supply of electricity for consumers. However, there are costs associated with provision of energy resources, which should be assessed against the value to consumers of having a secure supply. Frequency control frameworks should also seek to minimise distortions in order to promote the effective functioning of the market.

3. **Technology neutral:** 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.

4. **Flexibility:** Regulatory arrangements must be flexible to changing market and external conditions. They must be able to remain effective in achieving security outcomes over the long-term in a changing market environment. Regulatory or policy changes should not be implemented to address issues that arise at a specific point in time. Further, NEM-wide solutions should not be put in place to address issues that have arisen in a specific jurisdiction only. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions. They should be effective in facilitating security outcomes where it is needed, while not imposing undue market or compliance costs on other areas.

5. **Transparent, predictable and simple:** Frequency control frameworks should promote transparency as well as being predictable, so that market participants are informed about aspects that affect security, and so can make efficient investment and operational decisions. Simple frameworks tend to result in more predictable outcomes and are lower cost to implement, administer and participate in.

Question 5 Assessment principles

(a) Do stakeholders agree with the Commission's proposed assessment principles?

(b) Are there any other relevant principles that should be included in the assessment framework?

4.4 Assessment approach

The Commission intends to adopt the following approach to assessing frequency control markets and regulatory arrangements, and developing recommendations as part of this review:

1. Define the issues

The Commission considers that the first step in the assessment framework is to define the problem or issues that have been identified in relation to frequency control frameworks in the NEM.

Chapters 4 through 6 of this report seek to articulate the Commission's preliminary views on the issues that may need to be addressed, as well as seeking stakeholder views on the materiality of these issues, and whether there are any additional issues.

2. Determine the options available

The review will identify any changes to market and regulatory frameworks that will be required to address the issues identified through the above process. The review will consider both modifications to existing, as well as potentially new, mechanisms relating to the market- and intervention-based frameworks. It will also consider how these elements could address security in both the short- and long-term.

These options will identify potential changes to the existing frequency control frameworks that could better allow for efficient provision of frequency control, ultimately resulting in a secure electricity supply.

3. Assess the range of options against the NEO and guiding principles

Any recommendations for potential changes to market and regulatory frameworks developed by the Commission will need to result in net benefits to the market and promote the long-term interests of consumers, consistent with the NEO. The Commission's assessment of the options, and the development of recommendations in this review will also be guided by the framework principles set out above.

Question 6 Assessment approach

Are there any comments, or suggestions, on the Commission's proposed assessment approach?

5 Primary frequency control

The AEMC's *System security market frameworks review* identified a number of challenges that relate to maintaining system security as the power system shifts towards new forms of non-synchronous generation. The review identified changes in the power system that were contributing to degradation in frequency performance, including the decline in primary frequency control provided by generator governor response to frequency deviations within the normal operating frequency band, as described in section 3.1.4.[109]

The AEMC's final report for the review recommended an assessment of whether a mandatory governor response requirement should be re-introduced in the NEM to help improve frequency control.[110]

Through the *Frequency control frameworks review*, the AEMC will consider the appropriateness of the current regulatory arrangements that relate to the control of power system frequency.

This chapter:

- seeks stakeholder views on the materiality of the issues relating to primary frequency control
- sets out a number of potential options for changes to market and regulatory frameworks to improve frequency control under normal operating conditions, should any such changes be warranted.

5.1 Materiality of frequency control risks in relation to primary frequency control

The AEMC is interested to gain a more detailed understanding of the materiality of the risks associated with the observed changes in frequency performance within the NEM. This understanding will help the AEMC determine whether any changes to the existing regulatory frameworks are justified, including any requirement for mandatory governor response, and the potential timing of these changes.

5.1.1 Identifying the risks of reduced frequency performance

The AEMC recognises that continuous primary frequency control is an essential part of power system operation and that until recently this service has been provided free of charge (within the normal operating frequency band) by automatic generator governor response. The DIgSILENT analysis presents clear evidence that the prevalence of primary frequency control within the normal operating frequency band is in decline, and that there are risks associated with this decline. These risks include:

109 AEMC, *System Security Market Frameworks Review*, Final report, 27 June 2017, pp. 38-41.

110 AEMC, *System security market frameworks review*, Final report, 27 June 2017, p. 42.

- Generator impacts including:
  - an increase in the rate of wear and tear on mechanical generating equipment for those generators that respond to frequency changes within the normal operating frequency band, leading to increased costs associated with the maintenance of these generators
  - a decrease in the operational efficiency of mechanical generating equipment, especially where a generator continues to be responsive to frequency.
- An increase in FCAS costs as the quantities and utilisation of existing FCAS products increase in response to the increase variability of power system frequency.
- System security implications including:
  - increased potential for frequency oscillations
  - difficulty in AEMO meeting the performance standards set out in the frequency operating standard, due to an increased incidence of frequency deviations
  - potential for increased rate of change of frequency and maximum deviation in response to contingency events. Where the activation of primary frequency control services is delayed; a contingency event, such as the failure of a large generating unit, is likely to lead to a faster rate of change of frequency and larger frequency deviation than would otherwise be the case.- increased variability of interconnector flow on network interconnectors as the power system attempts to balance supply and demand following contingency events.[111]

As more generators remove their responsiveness to frequency deviations, within the normal operating frequency band, the remaining generators who are still responsive to frequency deviation are worked harder as a result of the increasing variability of the power system frequency. In the absence of any compensation for the provision of this frequency response "service", such generators operate at a disadvantage to other generators who are not responsive to frequency, creating incentives for those generators to in turn remove their primary frequency response capability. This creates a downward spiral of decreasing primary frequency control response within the normal operating frequency band.

Question 7	**Are stakeholders aware of any other costs or impacts linked to the degradation of frequency control performance in the NEM?**

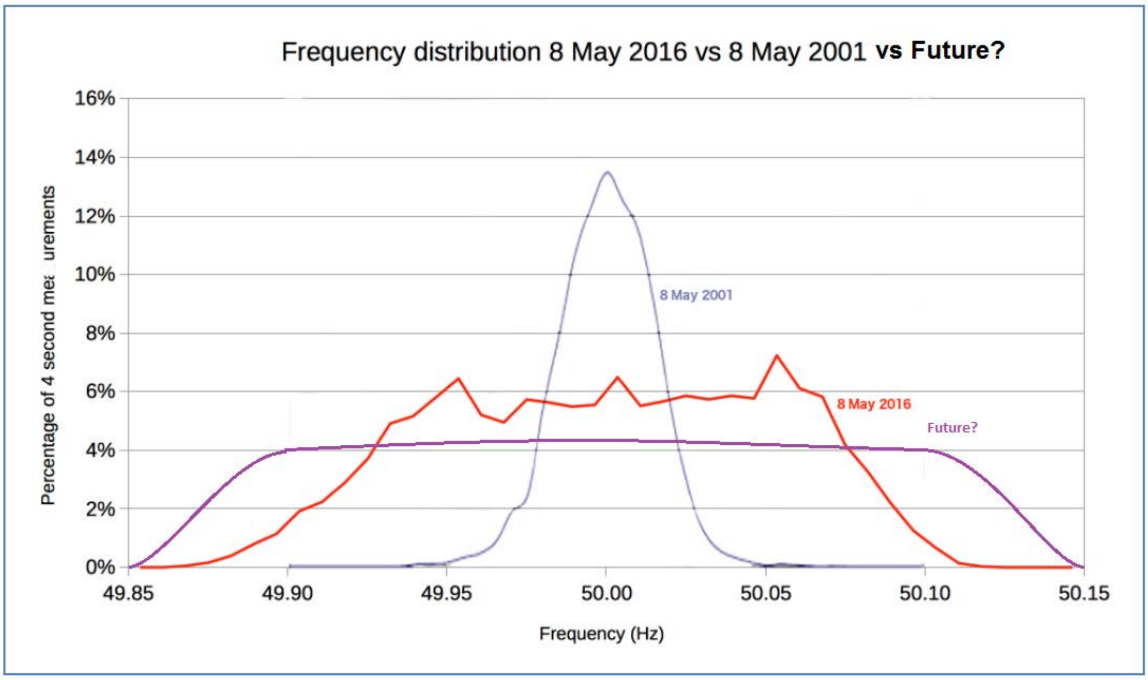
111 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017, section 5.3.

5.1.2 Assessing the materiality of the risk of reduced frequency performance

The Commission considers that further analysis is required to assess the scale of the economic and security impacts associated with each of the risks identified above. While frequency performance within the NEM has deteriorated in recent years, the Frequency Operating Standard is still largely being met, as evidenced by the improved frequency performance in June 2017, following a period of decline from December 2016 through to April 2017.[112]

In the absence of any change to the arrangements relating to frequency control within the normal operating frequency band, it is reasonable to expect a further flattening of the frequency distribution within the normal operating frequency band. Such a hypothetical future frequency distribution is shown in Figure 5.1. Importantly, such a distribution, while markedly different to historic distributions, is still within the current requirements of the frequency operating standard. The Commission is interested to hear from stakeholders in relation to perceived challenges for the operation of power system equipment associated with any such flattened frequency distribution.

Figure 5.1 Potential future frequency distribution profile for the NEM



Question 8	**Are there any other risks that stakeholders are aware of with respect to degradation of frequency control as represented by the flattened frequency distribution within the normal operating frequency band shown in Figure 5.1?**

112 AEMO 2017, Frequency monitoring – Three year historical trends, 9 August 2017, p. 4.

5.2 Options for improving frequency control in the NEM

In considering the options for improving frequency control during normal operation in the NEM it is necessary to recognise that the issue related to managing the power system frequency during normal operation is not that there is a lack of primary frequency control capability in the NEM. Rather the existing markets for primary frequency control services (contingency FCAS) do not require or reward a response until the frequency deviates outside of the normal operating frequency band. In essence the system dead band for the NEM is effectively the normal operating frequency band. In the absence of voluntary primary frequency control, the power system frequency is relatively free to wander within the normal operating band.[113] This wandering leads to increased exposure to the risks of poor frequency performance described in section 3.1.4.

As described in section 2.3, effective frequency control is achieved by having an integrated array of frequency control services that are able to control the system frequency and respond to different events that may cause frequency disturbances in different response times. Primary frequency control services offer an inherently fast response due to their local frequency measurement and action which is well suited to responding to rapid changes in generation or demand. Secondary frequency control services offer a delayed yet centrally controlled response that is well suited for correcting small persistent deviations in power system frequency.

A key question for this review is: Should a primary frequency control service be required to operate within the normal operating frequency band, and if so what mechanism is most appropriate to achieve this goal? Alternatively, can the existing secondary frequency control service, regulation FCAS and the AGC, be improved to provide adequate frequency control within the normal operating frequency band, with any primary frequency response being provided voluntarily? The potential mechanisms for improving frequency control within the normal operating frequency band are discussed in this section.

The following sections describe the Commission's initial thoughts in relation to these options to improve frequency control during normal operation.

- Section 5.2.1 provides a preliminary comparison of international arrangements for provision of primary frequency control.
- Section 5.2.2 outlines the Commission's initial thoughts in relation to the potential for the provision of primary frequency response to be a mandatory requirement.
- Section 5.2.3 describes contract-based procurement of primary frequency control by way of bilateral contracts or public tendering.

113 While regulating FCAS will act to restore the system frequency to 50Hz, the delayed response of this secondary frequency control service can not be expected to cancel out rapid changes in system frequency that are and expected component of normal system operation.

- Section 5.2.4 sets out the potential for procuring primary frequency control services through real-time markets (through existing or new FCAS markets).
- Section 5.2.5 describes potential improvements that may be made to the AGC and causer pays mechanisms that may improve the performance of secondary regulation services that currently control the power system frequency during normal operation. This includes recognition that the voluntary provision of primary frequency control under the current market and regulatory frameworks should not be discouraged.
- Section 5.2.6 provides a discussion of the potential benefit that may be gained from clarifying expectations in relation to frequency monitoring and reporting in the NEM.

5.2.1 International comparison of primary frequency control procurement mechanisms

The Commission has undertaken a preliminary desktop review of international arrangements for the provision of primary frequency control services and the respective frequency dead bands beyond which such services operate. A summary of this preliminary international review is included in Table 5.1.

The key findings of this international comparison are that:

- There is a diversity of mechanisms used for the provision of primary frequency control services, both mandatory and market based.
- The dead band for the provision of primary frequency control in most jurisdictions is narrower than ±0.05 Hz. Australia and New Zealand stand out in this regard with primary frequency control dead bands of ±0.15 Hz and ±0.20 Hz respectively.[114]

Many of the international jurisdictions in Table 5.1 have larger and more interconnected networks than the NEM, such as Germany, France and the western interconnection of the United States of America. These larger interconnected power systems tend to have more stable system frequencies than smaller power systems with relatively limited interconnection. Of the jurisdictions listed in Table 5.1, the transmission networks of Ireland and New Zealand are most similar to that of the

114 The Commission is aware that the Electricity Authority for New Zealand is currently undertaking a strategic review of Normal frequency management, including consideration of a narrow dead band of ±0.025 Hz as part of the asset owner performance obligations. The Commission intends to look more closely at the findings from the New Zealand Electricity Authority on this issue in preparing the draft report for this review. Electricity Authority, 2017, Normal frequency management - Strategic review - Information Paper, March 2017. Electricity Authority, 2014, Normal frequency asset owner performance obligations - Consultation Paper, June 2014.

NEM in terms of the level of renewable penetration and the relative scale and the geographical dispersion of the power systems.[115]

115 Ireland is only connected to the UK power system via the 500MW East West HVDC interconnector, which makes it an island in terms of frequency control.

Table 5.1 International comparison of primary frequency control procurement mechanisms[116]

	Non-market based		Market based			Dead-band (Hz)
	Mandatory – Paid	**Mandatory – Unpaid**	**Bilateral contract**	**Public tender**	**Real time market**	**Droop**
Australia					Capacity	±0.150 N/A
Argentina[117]		Energy (3 per cent reserve capacity)			Energy	±0.150 N/A[118]
Belgium		Energy	Capacity	Capacity		N/A N/A[119]

116 EY, 2014, 2014 Ancillary service standards and requirements study - Report to the Independent Market Operator (Western Australia), 4 November 2014. CIGRE, 2010, Ancillary Services: an overview of International Practices – Working Group C5.06, October 2010. CIGRE, 2010, Ancillary Services: an overview of International Practices – Working Group C5.06, October 2010

117 In the Argentinian power system, generators that offer more than 3 per cent frequency response capacity during real time market operation may receive more income, while those that offer less than 3 per cent are required to pay to the other generators for the additional reserve. ref: CAMMESA, Los Procedimientos - Anexo 23 - 3.2

118 The full 3 per cent response must be delivered prior to the frequency deviation exceeding ±0.15 Hz, as set out in the seasonally adjusted procedure: CAMMESA, Regulacion Primaria de Frecuencia, November 2017 - April 2018.

119 Technical requirements set out in the delivery contract. European Network of Transmission System Operators for Electricity, 2012, Network code for requirements for grid connection applicable to all generators – Requirements in the context of present practises, 26 June 2012, p.16.

	Non-market based		Market based			Dead-band (Hz)
	Mandatory – Paid	**Mandatory – Unpaid**	**Bilateral contract**	**Public tender**	**Real time market**	**Droop**
Czech Republic				Capacity		0.000[120] 8%[121]
Finland	Capacity					±0.050[122] 2-8%[123]
France			Capacity			±0.001[124] N/A[125]
Germany				Capacity (monthly)		±0.020 4 – 8%

120 European Network of Transmission System Operators for Electricity, 2012, Network code for requirements for grid connection applicable to all generators – Requirements in the context of present practises, 26 June 2012,p.16.

121 Ibid.

122 Ibid.

123 Ibid.

124 Réseau de Transport d'Électricité (RTE), 2014, Documentation Technique de Référence, 1 January 2014, clause 4.1.3.

125 Ibid.

	Non-market based		Market based			Dead-band (Hz)
	Mandatory – Paid	**Mandatory – Unpaid**	**Bilateral contract**	**Public tender**	**Real time market**	**Droop**
Ireland	Energy (regulated tariff)					±0.015 2-10%
New Zealand			Capacity (lower reserve)		Capacity (regulation and raise reserve)	±0.200 0-7%
Spain		Capacity and energy				±0.01 N/A[126]
UK (England and Wales)[127]	Capacity and energy		Capacity and energy			±0.015 3-5%
USA (California) - Western Interconnection				Capacity		±0.036 dead band 4% droop (gas turbine), 5% droop (all others)[128]

126 Droop as instructed by system operator.

127 The UK national grid pays frequency response service providers a holding payment in £/hr and an energy payment in £/MWhr. Large generators over 100MW and medium generators over 50MW that are connected to the transmission system must provide the frequency response service. Other generators may request to provide the frequency response service by agreement with National Grid. National Grid, 2013, Mandatory Services - Frequently asked questions, version 1.0, May 2013, p.7.

128 NERC, Reliability Guideline - Primary Frequency Control, 15 December 2015, p. 9.

Question 9	**Are stakeholders aware of any other international experience in relation to primary frequency control that is relevant for this review of frequency control frameworks in the NEM?**

5.2.2 Mandatory provision of primary frequency control

One option for the provision of primary frequency control is for primary frequency response to be a mandatory requirement for all generators. Such an obligation may be incorporated into the generator technical performance standards that apply for generator connection agreements, or via some alternative mechanisms within the NER. As discussed in section 2.5.2, such a requirement was a feature of the NEM, prior to the introduction of FCAS markets over the period from 1999 through to 2003.[129]

The mandatory requirement for the provision of primary frequency response would likely provide the highest level of system security and stability, based on the assumption that such a mechanism may include a required reserve capacity. It is likely that such a mandatory requirement will effectively achieve a high level of security through the over procurement of primary frequency control capacity. It is also likely to more evenly distribute the primary frequency response across the power system.

The distribution of frequency response may reduce the individual cost burden by spreading the requirements to provide primary frequency response across all generators.

The geographic diversity of frequency response may help to stabilise interconnector flows and may increase the resilience of regions of the power system to significant contingency events with the potential to cause inter-regional separation and islanding.

The Commission is aware that the costs of providing primary frequency control vary between different generating units and that a mandatory requirement does not allow for such services to be preferentially provided by generators who can do so at lowest cost. The Commission is aware that for some generators the provision of primary frequency response within the normal operating frequency band is a straightforward control system change, whereas other generators may require capital investment and plant upgrades in order to be able to provide such functionality.

This obligation could be applied exclusively to new entrants or also to existing generators. If such a requirement were to apply to already connected generators, then it is likely that the performance standards for these generators would need to be

129 At that time the dead band that applied for the provision of this governor response was set at ± 0.05Hz or 49.95 – 50.05 Hz and the normal operating frequency band was set at ± 0.1Hz or 49.90 – 50.10 Hz.

renegotiated with the NSP and AEMO.[130] This is not straightforward because it would involve an opening up of and renegotiation of existing connection agreements. The Commission has considered the difficulty of renegotiating existing contracts in the *Generator technical performance standards* rule change.[131] As such renegotiation is not a straightforward task, the Commission would need to consider the most appropriate way to implement a mandatory requirement for the provision of primary frequency control and the impact of any mandatory requirement on the accrued rights of generators with pre-existing connection agreements.[132]

A mandatory requirement could be implemented as a paid or an unpaid service. Payments for a mandatory service would likely be made on the basis of the provision of the service, as the intent of such payments are to cover the costs incurred by generators in providing the frequency response. An example of this is the current arrangement in the Irish power system operated by EirGrid. In Ireland, all generating units are required to be operated with a governor control system that is responsive to changes in system frequency outside a dead band of no greater than ±0.015Hz.[133] The primary frequency response provided by each generator to help regulate the EirGrid system frequency is then paid on the basis of a flat rate per MWh.[134]

Alternatively the provision of primary frequency response could be treated as a general generator performance obligation, similar to other generator technical performance standards such as power quality and frequency ride through capability. Generators are not financially rewarded for meeting such performance standards, rather they are a requirement that must be met in order to connect to the network.

A key consideration of imposing a mandatory obligation on generators to provide primary frequency services is the required technical performance criteria for such an obligation. These technical performance criteria could include:

- the required size of the variation of active power in MW with respect to a generators registered capacity
- the response time to deliver the change in active power measured in seconds
- the duration of time that the generator can sustain the increase or decrease of active power

130 AEMO has a role in advising on negotiated access standards that are AEMO advisory matters, as defined by clause 5.3.4A(a) of the NER. An AEMO advisory matter is a matter that relates to AEMO's functions under the NEL and a matter in which AEMO has a role in schedules 5.1a, 5.1, 5.2, 5.3 and 5.3a of the NER.

131 AEMC, 2017, *Generator technical performance standards* – Consultation Paper, 19 September 2017, pp. 46-47.

132 Such consideration would include any impact on existing rights and liabilities in any of the ways described in paragraphs (a)-(e) of clause 33(1) of Schedule 2 to the NEL.

133 EirGrid, 2015, Grid Code Version 6.0, OC4.3.4.

134 EirGrid, 2017, *Harmonised Other System Charges Consultation* - Tariff Year 01 October 2017 to 30 September 2018, 4 April 2017, pp.14-15.

- the size of any reduced output associated with generator recovery following the provision of the initial frequency response
- any recovery time associated with the provision of the initial frequency response.

The size, response time and duration of response are common characteristics for any active power variation that provides a frequency response. Recovery periods associated with providing a frequency response service are specific to certain generation technologies such as wind turbines.[135]

Multiple options for the provision of primary frequency control headroom and service delivery

The commission notes that effective frequency control can be broken down into the following three service components:

- the technical capability of the generator to vary active power in response to power system frequency
- the availability of responsive generation capacity or headroom
- the operational variation of active power in response to changes in power system frequency.

The requirement for generators to possess the capability to provide active power control is being considered through the *Generator technical performance standards rule change*.[136] Through this rule change, the Commission is considering a proposal by AEMO for new large scale generation to be required to have the capability to be able to provide a primary and secondary frequency response.[137] The Commission recognises the interaction between this element of the generator technical performance standards and the frameworks that apply for the provision of frequency control services.

This review will consider whether it is appropriate for new mechanism(s) to be created to support or require the availability and delivery of the remaining service components: headroom and active power response. The commission notes the potential for more than one mechanism to be used to deliver these service components. For example, a generator may be required to be meet a mandatory requirement to be responsive to changes in frequency outside of a minimum dead band, but the capacity or headroom to provide an increase in active power may be purchased separately through a contract or real time market as described in the following sections.

In considering any mechanism for the provision of primary frequency control services, the commission is interested to understand whether the mechanism includes appropriate consideration of any regional requirements for primary frequency control.

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135 DGA Consulting, 2017, *International review of frequency control adaption* – Australian Energy Market Operator, 14 October 2016, pp.90-93.

136 AEMC, 2017, *Generator technical performance standards* – Consultation Paper, 19 September 2017

137 Ibid. pp.32-33.

Such regional requirements may be required to apply at all times, as is the case for minimum inertia requirements, or alternatively they may only apply when there is a credible risk of separation, as is currently the case for FCAS.

Question 10 Mandatory primary frequency control

(a) What are the advantages and disadvantages of mandating primary control for all generators in order to improve frequency control during normal power system operation?

(b) What factors should be considered in the specification of a mandatory primary frequency control response?

(c) Are there any regional issues that should be considered in assessing whether primary frequency response should be a mandatory obligation for registered generators in the NEM?

(d) Should an obligation for generators to be responsive to changes in system frequency outside a pre-defined dead band include a required availability reserve, such as 3 per cent of a generators registered capacity, as is the case in Argentina?

5.2.3 Contract based procurement of primary frequency control

One alternative mechanism for provision of primary frequency control during normal operation is via a contract procurement model. Under such a model, AEMO would specify the performance characteristics and quantity of primary frequency response and this criteria would be incorporated into a contract for services that may be made between the service provider and AEMO or potentially a TNSP. Contracts could be established via a competitive tender process or bilaterally negotiated process. The Commission may consider whether such a contracting process would be set out in the NER as is the case for system restart ancillary services and network support ancillary services, or it could be managed outside the NER by AEMO.

Service providers would not be limited to generators capable of providing a governor response. Any market participant with the ability to control the active power supply or demand at their connection point in response to variations in powers system frequency could provide the service.

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

Question 11	**What are the advantages and disadvantages of procuring primary control through bilateral contracting as a means to improve frequency control during normal power system operation?**

5.2.4 Market based options for primary frequency control

Some form of real time market would provide a flexible and adaptive mechanism for the procurement of primary frequency control services. Under such a market procurement approach, it is likely that AEMO would determine the quantity of primary frequency control services required to assist with regulating the frequency during normal operation. Depending on the exact design of such a market, the dispatch of this "primary regulating" FCAS could potentially be co-optimised with energy as is currently the case for FCAS dispatched through NEMDE.

It is possible for the market based procurement of primary frequency control services during normal operation to be achieved under two broad market design approaches:

- Utilisation of the current FCAS markets
- Through the creation of new FCAS markets for primary frequency regulation services

The goal of each of these approaches is to trigger the operation of primary frequency response when the frequency deviates outside of some frequency band that is narrower than the existing normal operating frequency band.

For the purpose of discussion, the narrow trigger band for this primary frequency response is shown in Figure 5.2 as ± 0.05 Hz. However, the Commission recognises that this trigger band (or dead band) would be subject to further consideration and analysis as part of the design of a market mechanism for the provision of primary frequency regulation services.

Utilisation of the existing FCAS markets

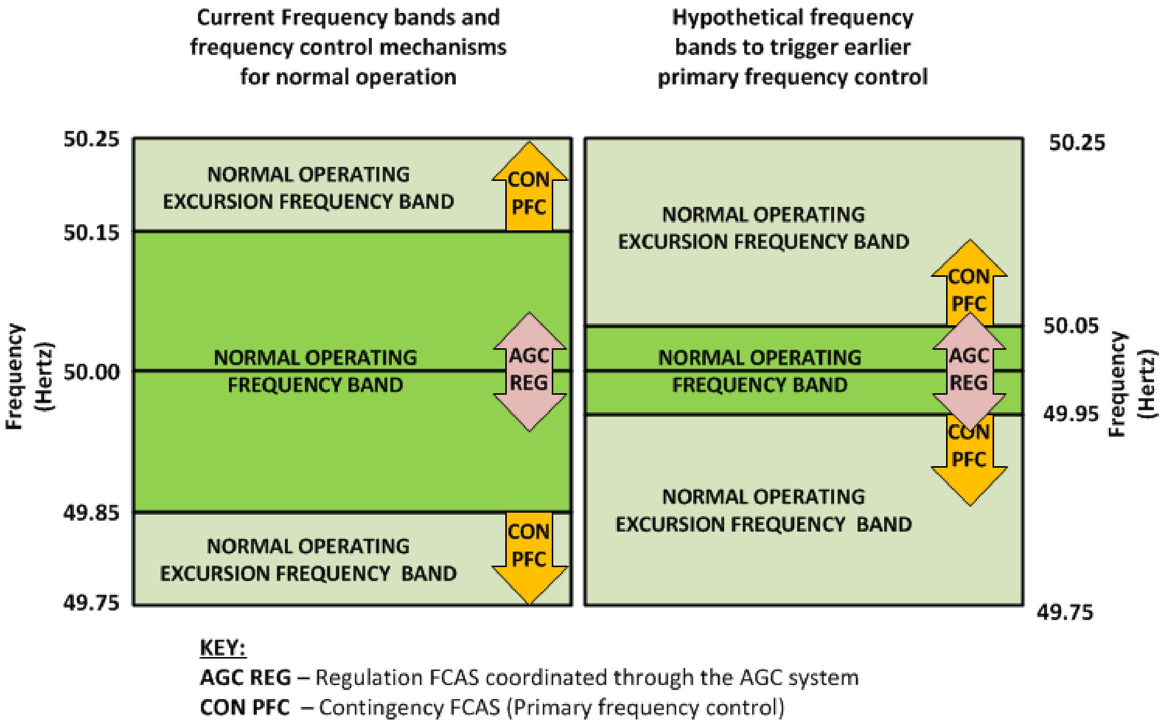
It is technically feasible to achieve an earlier activation of primary frequency control services through the modification of the frequency settings that relate to the existing contingency FCAS services as described in section 2.4.2. These contingency services are dispatched through the established FCAS markets and triggered in response to local frequency measurement in accordance with the individual frequency settings that are allocated by AEMO. The basis for these frequency settings is set out in AEMO's Market Ancillary Service Specification (MASS) which is in turn written with reference to the frequency bands specified in the frequency operating standard.[138]

The current requirement in the frequency operating standard is that, for 99 per cent of the time, the power system is maintained within the normal operating frequency band

138 AEMO, 2017, Market ancillary service specification, 30 June 2017.

of 49.85 – 50.15Hz. During normal operation, in the absence of a contingency or load event, there is an allowance for brief excursions outside this band, but within the normal operating excursion frequency band of 49.75 - 50.25 Hz.[139] Under this arrangement, regulating FCAS provides secondary frequency control via the AGC system within the normal operating frequency band and primary frequency control is provided by contingency FCAS when the power system frequency deviates outside of 49.85 – 50.15Hz. This is shown on the left hand side of Figure 5.2.

Figure 5.2 Frequency bands for market primary frequency control under current market frameworks



In theory the primary frequency control service provided by the existing contingency FCAS mechanism could be triggered earlier by narrowing the normal operating frequency band to 49.95 - 50.05 Hz, as shown on the right hand side of Figure 5.2.[140] Under such an approach the goal of frequency control during normal operation would be to maintain the power system frequency with the normal operating excursion frequency band of 49.75 - 50.25 Hz in the absence of a significant contingency event.

It would be expected that the utilisation of contingency FCAS would increase under such a scenario, and it is likely that the cost of this service would increase as service providers price in the additional wear and tear associated with this increased utilisation. It is also likely that the utilisation and overall cost of the existing regulation

139 Under normal operating conditions, in the absence of a contingency event, if the power system frequency deviates outside the normal operating frequency band, it must be returned to the normal operating frequency band within 5 minutes.

140 The narrow band of 49.95 - 50.05 Hz is used here as a provisional band for discussion purposes only, the exact band could be wider or narrower subject to more detailed analysis and design of such settings.

services decrease as the contingency services take on a greater role in controlling system frequency.[141]

The Commission recognises that the Reliability Panel is the decision maker for any change to the frequency operating standard. However, such a change to the approach to frequency control in the NEM may have implications for other market processes. This may include:

- implications for the determination of the causer pays contribution factors and the allocation of costs for frequency control more generally
- implications for the availability of frequency response capacity to respond to significant contingency events, such as the failure of a large generator
- consideration of whether the requirement in the Frequency operating standard to maintain the frequency within the normal operating frequency band for 99 per cent of the time is consistent and reasonable with such a narrow frequency band
- whether there should be multiple classes of contingency events, such as an "ordinary contingency" where frequency is maintained within the normal operating excursion frequency band and an "extra-ordinary contingency" where frequency is contained within the operational frequency tolerance band.[142]

The formation of new FCAS markets for primary frequency control

Alternatively, the provision of primary frequency control services during normal operation could be incentivised through the formation of new FCAS markets for regulating primary frequency control services. Such an approach may not necessarily require any change to the existing frequency bands in the frequency operating standards, nor to the existing FCAS markets.

Setting up separate markets for raise and lower regulating primary frequency control services would allow AEMO to prescribe the required amount of each type of FCAS dynamically in response to changing power system conditions and for these services to

141 This approach to frequency control would bring forward the activation of frequency control services that respond to frequency disturbances, including variation in actual generation or demand from forecast generation and demand. This relates to the proposed change to the definition of generation event set out in the Draft Determination of the Reliability Panel's Review of the frequency operating standard. The draft frequency operating standard includes a revised definition of 'generation event' which includes the sudden, unexpected and significant change in output from one or more generating systems of 50MW or more within a 30 second period. This change was requested by AEMO to help it manage sudden variations of generation output from the increasing quantity of larger variable renewable generation power stations (such as large scale solar PV farms) expected over coming years. AEMO's advice to the Panel is that regulation FCAS is poorly suited to managing such sudden and significant variations in generation output and that fast acting contingency FCAS is the more appropriate frequency control service.

142 The normal operating excursion frequency band is 49.75 – 50.25 Hz for Tasmania and the mainland, the operation frequency tolerance band is 49.0 Hz to 51.0 Hz for the mainland frequency operating standard and 48.0 Hz to 52.0 Hz for Tasmanian frequency operating standard.

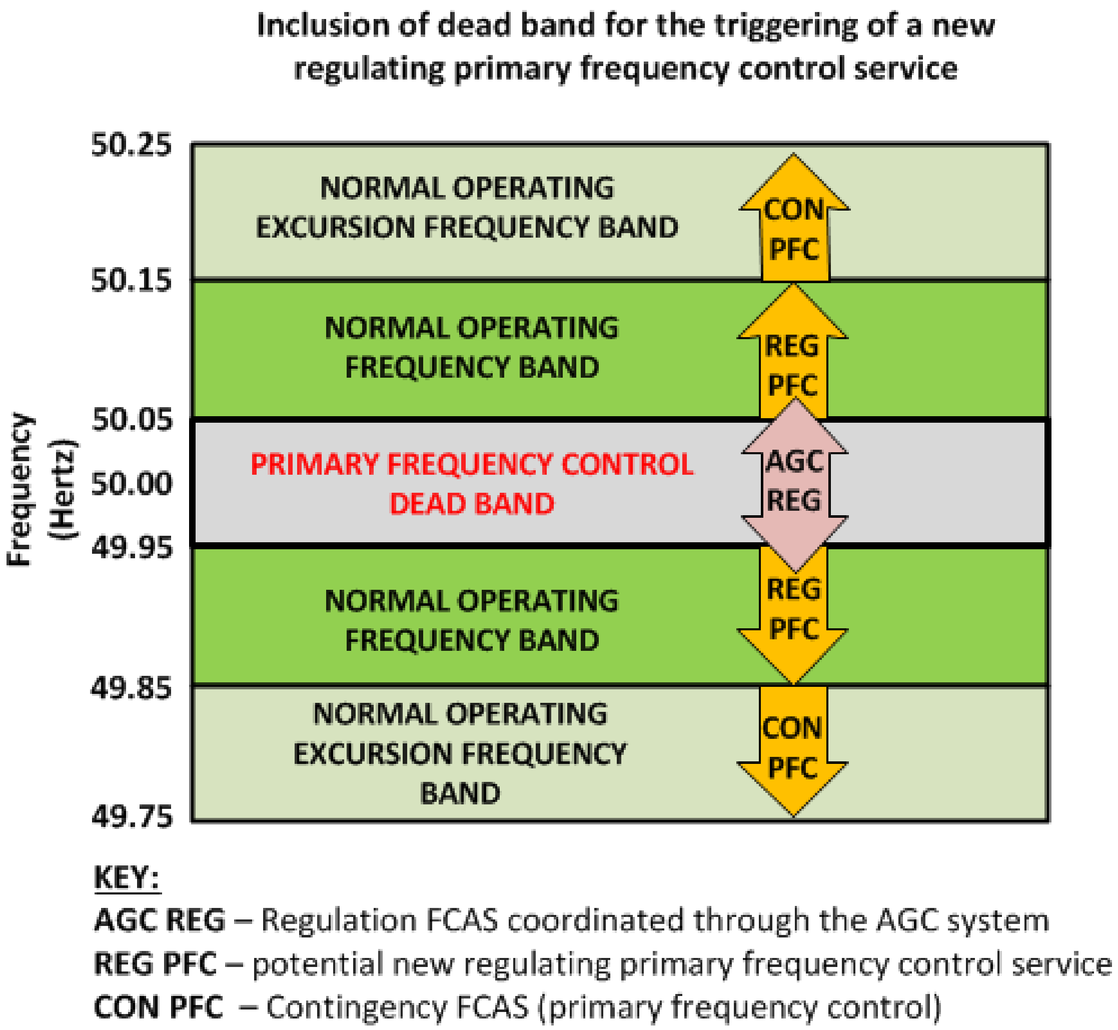
be co-optimised through NEMDE as is currently the case for regulation and contingency services.

Figure 4.7 shows how these potential new regulating primary frequency control services may operate in relation to the existing frequency bands, and frequency control services. The primary frequency control dead band is shown notionally at ± 0.05Hz and represents the trigger point for these new services. This dead band is a key variable for such a service and the commission would require further analysis and advice to inform the determination of this dead band setting. The commission would also need to consider whether such a dead band would be specified in the frequency operating standard or in the NER and the implication of each of these options.

This change would also impact the determination of causer pays contribution factors which would need to be further considered through the course of this review.

The formation of new FCAS markets to provide improved frequency control outcomes in the NEM is discussed further in chapter 5.

Figure 5.3 Frequency bands and primary frequency dead band for a new primary regulation service



Potential application of fast frequency response for primary frequency control

In the past primary frequency control was provided by the governors that controlled the output of synchronous generators. However, as the generation technology in the NEM changes due to the increase in renewable and inverter-connected generation, it is more appropriate for generators or load to provide "active power control" when required, rather than governor response. This differentiation in terminology was recognised by AEMO in their recent working paper titled *Fast frequency response in the NEM*, the paper defined fast frequency response as:[143]

> "Any type of rapid active power increase or decrease by generation or load, in a timeframe of less than two seconds, to correct supply-demand imbalances and assist with managing frequency."

The commission understands that a resilient approach to the delivery of primary frequency control will be inclusive of any available technology that can deliver the desired control response. The fundamental characteristics of such a primary frequency control service may be broadly defined as:

- The controlled variation of active power from a generator or load within a defined period of time in response to a deviation of power system frequency outside of a defined dead-band, to correct supply-demand imbalances and assist with managing frequency.

Question 12 Market based options for primary frequency control

(a) What are the advantages and disadvantages associated with the two options presented for earlier provision of primary frequency control:

(i) Using the existing contingency FCAS for provision of primary frequency control and narrow the normal operating frequency band to trigger a primary frequency response closer to 50 Hz.

(ii) The establishment of a new primary regulating service to provide primary frequency control within the normal operating frequency band, separate from contingency FCAS.

5.2.5 Changes to AGC and causer pays arrangements

There may be the opportunity to realise improvements in frequency control through improving the operation and effectiveness of regulating FCAS and the AGC system which provides secondary frequency control services.

The Commission understands that AEMO is progressing an internal work program to improve the performance of the AGC system and improve the compliance and verification in relation to regulation services.

143 AEMO, 2017, *Fast frequency response in the NEM* – working paper, August 2017, p. 17.

The DIgSILENT analysis identified that one of the main drivers of the removal and detuning of primary frequency response from existing synchronous generation, is a perception by generators that provision of primary frequency response acts to increase "causer pays" contribution factors. AEMO is responsible for determining this causer pays procedure which is used to allocate costs associated with regulation services to market participants who are determined to have contributed to frequency deviations. The NER sets out principles for the determination of contribution factors for the allocation of costs associated with regulation services. These principles include that:[144]

> “a scheduled participant) will not be assessed as contributing to the deviation in the frequency of the power system if within a dispatch interval:
>
> [...]
>
> (iii) the Scheduled Participant is not enabled to provide a market ancillary service, but responds to a need for regulation services in a way which tends to reduce the aggregate deviation;”

This means that a generator that assists with frequency control in such a way that reduces the need for regulation services should not be penalised for providing such a frequency response.

The Commission understands that the current causer pays procedure aggregates all of the contribution factors from each generating unit within a generator’s portfolio over the 28 day sample period and discards any net positive contribution factors.[145] Under this procedure a positive contribution factor represents a generation portfolio that, on aggregate, helped to manage disturbances in power system frequency while a negative contribution factor denotes a generation portfolio that on aggregate contributed to deviations in power system frequency. The intent of this process is that a generator who provides frequency response that assists with frequency control is able to offset that response against any negative contributions within their portfolio and that any participant with a net positive contribution factors will not be liable for contributing towards the cost of regulating services for that period.

AEMO is in the process of consulting on potential improvements to the causer pays procedure that may help remove any penalties, or the perception of penalties, associated with the provision of primary frequency control and the allocation of costs for the provision of regulating FCAS.[146]

The commission recognise that there is the potential for the framework relating to the causer pays contribution factors to be modified such that participants with a net positive contribution factor are able to be financially rewarded for assisting with

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144 Clause 3.15.6A(k)(5)(iii) of the NER.

145 AEMO, 2017, Causer pays procedure, version 5, 3 March 2017, p. 23.

146 See: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Causer-Pays-Procedure-Consultation

regulating the power system frequency during normal operation. This method of incentivising the provision of primary frequency control will be considered along with other potential options for improving primary frequency control during the course of this review.

Question 13	Are there any aspects of the existing Causer pays procedure that stakeholders believe are acting to discourage the voluntary provision of primary frequency response?

5.2.6 Frequency monitoring and reporting

Through recent consultation for the Reliability Panel *Review of the frequency operating standard*, a number of stakeholders expressed support for AEMO to be required to report periodically on frequency performance in the NEM.[147]

The NER does not currently contain any requirement for AEMO to report regularly on power system frequency performance. AEMO is required to report on any "reviewable operating incident" that occurs in the NEM, including an event where the frequency of the power system is outside limits specified in the power system security standards.[148]

To date AEMO produce frequency monitoring reports on ad hoc basis, with the most recent reports being published in December 2016 and August 2017.[149] These reports include a three year history of:

- monthly averages for the percentage of time that the power system frequency is within the normal operating frequency band over a 30 day period for the mainland NEM and for Tasmania.
- the number of exceedance events on a monthly basis for each of the bands in the frequency operating standard, including:
  - the normal operating frequency band
  - the normal operating excursion frequency band
  - the operational frequency tolerance band
  - the extreme frequency tolerance excursion limit.

The Commission is interested to hear from stakeholders in relation to whether there are any perceived benefits to market participants from more frequency reporting of

147 Reliability Panel, *Review of the frequency operating standard*, submission to the issues paper: ENA, p. 4; TasNetworks, p. 8; HydroTasmania, p. 1.

148 See clause 4.8.15(iii) of the NER.

149 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Frequency-and-time-error-monitoring

frequency performance in the NEM and what frequency metrics stakeholders feel are most valuable.

Question 14 Frequency monitoring and reporting

(a) What are the potential benefits or costs associated with a requirement for AEMO to produce regular frequency monitoring reports?

(b) What metrics should such frequency monitoring reports include?

6 FCAS markets

The operating characteristics of the NEM are changing with the increased penetration of intermittent generation such as wind and solar farms and distributed rooftop solar PV, together with the expected age-related retirement of major thermal power stations over the next five to ten years. As set out in chapter 3, a key implication of these changes is the potential for greater challenges in system frequency control.

Conversely, there are also emerging opportunities for new sources of FCAS, such as from wind farms and energy storage, and of demand response as a significant FCAS provider. These challenges and opportunities call into question the need for changes to FCAS frameworks to make sure they remain suitable and sufficiently flexible so as not to preclude the participation of emerging technologies.

This chapter provides an overview of the proposed review of FCAS markets, including:

- the design characteristics of market ancillary services in the NEM
- the determination of FCAS requirements and the potential introduction of FFR services
- potential changes to existing FCAS frameworks and cost recovery arrangements
- the potential co-optimisation of FCAS with inertia.

6.1 Review of FCAS markets

The need for a review of FCAS markets was identified in the final report of the *System security market frameworks review*, which concluded:[150]

> "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."

150 AEMC, System security market frameworks review, final report, p. v.

These conclusions underpinned recommendation six in the final report, which was included within the terms of reference for the *Frequency control frameworks review*, namely to 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
- any longer-term options to facilitate co-optimisation between FCAS and inertia provision.

6.2 Design of FCAS markets

An important design characteristic of FCAS markets in the NEM is that participants 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 AGC signal sent by AEMO (for regulation FCAS), or automatically in response to a frequency disturbance measured by the generator (for contingency FCAS, that is, fast, slow and delayed services). 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.

Under the NER, market participants that have classified their units to provide ancillary services and have submitted an offer in respect of that unit are required to ensure that they are able to receive and immediately act upon dispatch instructions (which includes ancillary services instructions) issued to them by AEMO.[151] The AER monitors and enforces compliance with this rule.

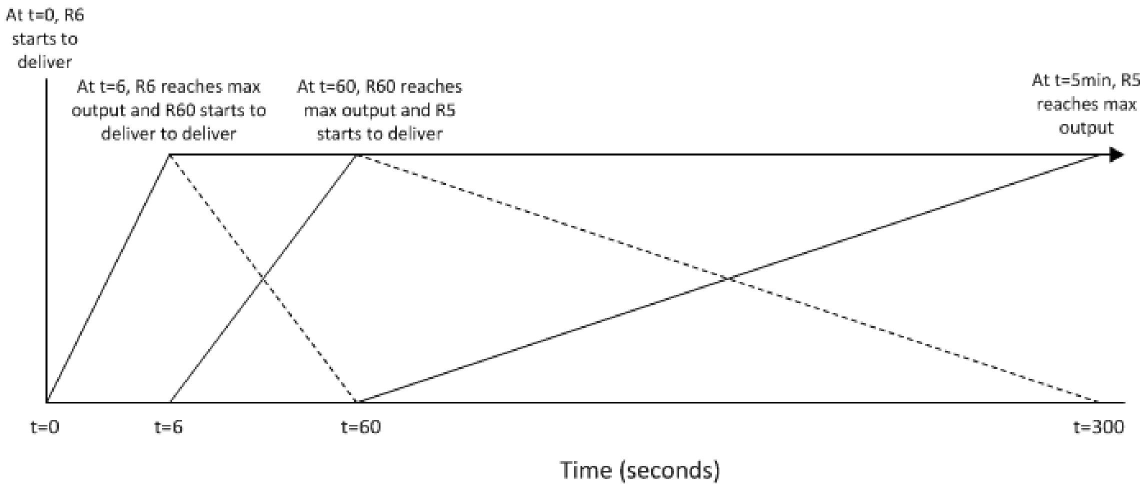
As noted in section 2.4.2, the NER only provide high level descriptions of FCAS services. The NER also require that AEMO prepares a market ancillary service specification (MASS) containing a detailed description of each kind of market ancillary service together with relevant performance parameters and requirements.[152]

Under the MASS, the current fastest service is the six second service contingency FCAS 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) and subsequently, delayed (five-minute) services. This progression is illustrated in Figure 6.1.

151 See clause 4.9.3A of the NER.

152 See clause 3.11.2(b) of the NER.

Figure 6.1 Interaction of fast, slow and delayed FCAS services



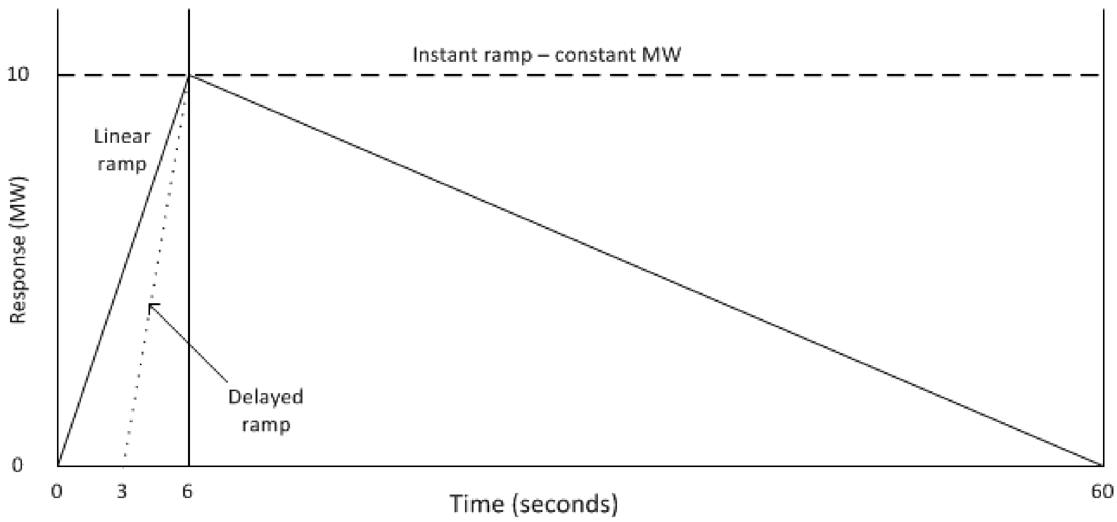
The definition of the six second service is quite flexible in that generator participation simply requires some level of ability to respond to a frequency disturbance in a six second time frame and to sustain some level of that response for up to sixty seconds.

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 (ramping adjusted) 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.

6.2.1 Application of MASS measurement framework

Figure 6.2 below illustrates the application of the MASS measurement approach to the six second service.

Figure 6.2 Six second FCAS MW profile



In this example, there are three separate 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:

- *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.

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

- *Delayed ramp profile* – 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.

6.2.2 Impact of FCAS measurement framework

A key characteristic associated with the existing FCAS measurement approach is that it recognises the speed at which FCAS can be provided so that a generator that can provide a faster service (and sustain it over the measurement period) will be credited with a higher MW enabled and therefore receive a higher payment.

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. 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.

6.3 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.

As the size of system disturbances increases and as the amount of inertia decreases, the amount and/or speed of FCAS response needed to keep system frequency within the frequency operating standard (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 considering the introduction of faster response FCAS, as well as sourcing FCAS from new technologies or less conventional sources such as distributed energy resources. A discussion on the potential participation of distributed energy resources in ancillary service markets is set out in chapter 7.

6.3.1 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 Future Power System Security program.[153] 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.

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
- FFR services, to rebalance supply and demand more quickly than existing FCAS services.

This mix of responses was recognised in the final report of the AEMC's *System security market frameworks review* and underpinned the rationale for the Commission's *Managing the rate of change of power system frequency* final rule determination in September 2017. The final rule places an obligation on TNSPs to procure minimum required levels of inertia or alternative frequency control services to provide a high degree of confidence that the power system can be maintained in a secure operating state under a range of different conditions.

6.3.2 Defining FFR

In August 2017 AEMO released a working paper seeking to create a common language for discussing FFR services. In that paper, AEMO noted that "FFR generally refers to the delivery of a rapid active power increase or decrease by generation or load in a timeframe of two seconds or less, to correct a supply-demand imbalance and assist in managing power system frequency."[154]

In seeking to identify the potential benefits of FFR, AEMO, as part of its Future Power System Security work program, commissioned GE to report on technology capabilities for FFR. GE noted:[155]

> "There is a delicate interplay between FFR, primary frequency control (PFR) and inertia. The primary function of FFR is to arrest the frequency

153 AEMO, Future Power System Program, Progress report, August 2016, p. 17.

154 AEMO, Future Power System Security Program Working Paper, Fast Frequency Response in the NEM, August 2017, p. 3.

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

> decline and "buy time" for PFR to act.[156] 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 Future Power System Security work program, AEMO has reached a view that FFR is likely to become increasingly important in the future as system inertia levels continue to decrease:[157]

> "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 ... At this point, it will become extremely valuable to have a large, competitive pool of FFR providers available."

It is important to note that in September 2017 the AEMC made a rule that requires TNSPs to procure minimum required levels of inertia or alternative frequency control services to meet these minimum levels.[158] It is expected that this new requirement will provide confidence that system security can be maintained in all regions of the NEM while minimising the cost to consumers.

AEMO also noted the broad range of services that fall within the FFR category and reinforced this theme in its working paper, which noted that:[159]

> "…frequency control in the NEM is currently achieved via a combination of frequency control services which act over different timescales and have different roles. They are also activated via different mechanisms. For example, following a contingency event, inertia slows the RoCoF, allowing time for governor response and contingency Frequency Control Ancillary Services (FCAS) to arrest the frequency change. Slower types of contingency FCAS and regulation FCAS then act to restore the frequency to its nominal value of 50 Hertz (Hz). "

AEMO went on to comment that "the services identified as immediate FFR opportunities either fulfil similar roles or utilise similar mechanisms but on faster timeframes to existing services. In general, these particular FFR services will not act as

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

157 AEMO, submission to the *System security market frameworks review* interim report, p. 18.

158 See: http://www.aemc.gov.au/Rule-Changes/Managing-the-rate-of-change-of-power-system-freque

159 AEMO, Future Power System Security Program Working Paper, Fast Frequency Response in the NEM, August 2017, p. 4.

a replacement but rather complement the existing services due to their different properties."[160]

In the FFR working paper, stakeholder comment was invited by 29 September 2017, specifically:[161]

> "AEMO welcomes evidence-based feedback on the technical findings set out in this report, preferably supported by analysis. Views on potential FFR services are also invited. All feedback will inform AEMO's forward work program."

At the time of preparation of this report at end October 2017, no submissions had been published by AEMO. The AEMC intends to await outcomes from this work stream prior to progressing FFR issues within this *Frequency control frameworks review*.

At this time, we have adopted the advice provided by AEMO as to how FFR might emerge in the NEM. Namely:[162]

- Emergency response FFR is being implemented immediately as a part of the SPS under development to protect against or prevent the loss of the Heywood interconnector connecting South Australia to Victoria.
- Contingency FFR and primary frequency control show promise in the near term.
- Fast response regulation may become important in future, and is technically feasible at present.
- Simulated inertia and grid-forming technologies are not yet commercially demonstrated.

Question 15 Defining FFR

What are your views on AEMO's advice on how and when FFR might emerge in the NEM?

6.4 Changes to FCAS frameworks

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 these markets remain relevant in terms of meeting the emerging needs of frequency control in the NEM.

160 Ibid, p. 4.

161 Ibid, p. 11.

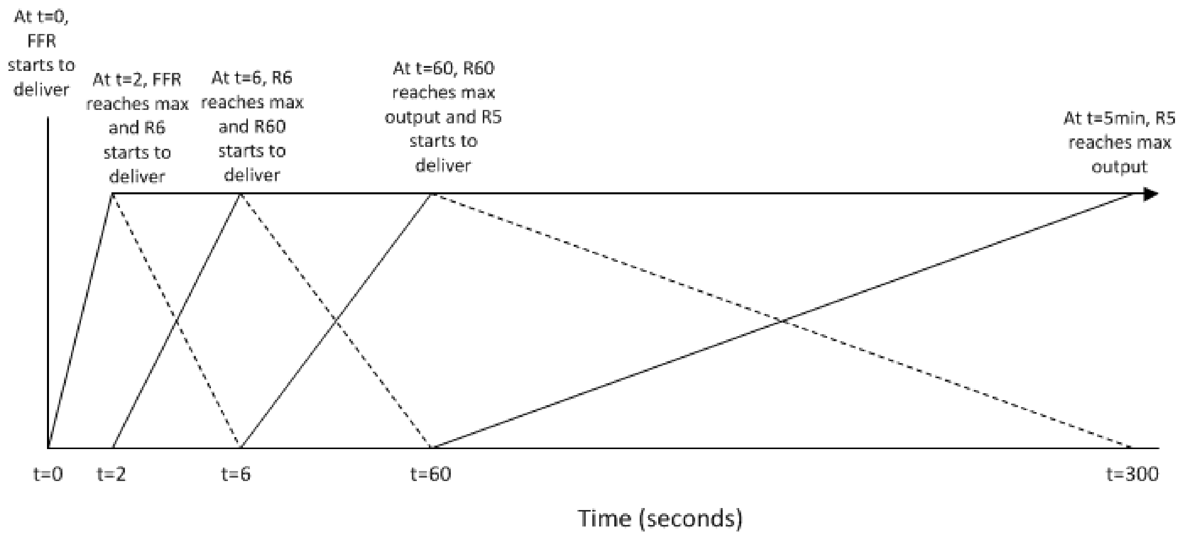
162 AEMO, Future Power System Security Program Working Paper, Fast Frequency Response in the NEM, August 2017, p. 5.

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 the service characteristics should be?

6.4.1 Potential options for making changes to FCAS frameworks

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.[163] The impact of introducing a two second FFR service while retaining existing services (with the current fast service redefined to incorporate an additional two second service) is shown in the following figure.

Figure 6.3 Incorporation of two second FFR in contingency FCAS services



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 is the potential for multiple FFR markets to be introduced to capture different response elements that are valuable to the system.

Importantly, introducing an additional FFR market would increase the granularity of the FCAS markets and therefore may provide better price signals for the value of fast response services. However, in circumstances where the ideal FFR service characteristics are not clear, 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.

The development of a new FCAS market or markets is likely to be complex and time consuming and would need to incorporate a review of the relevance of the current FCAS market definitions as set out in the MASS.

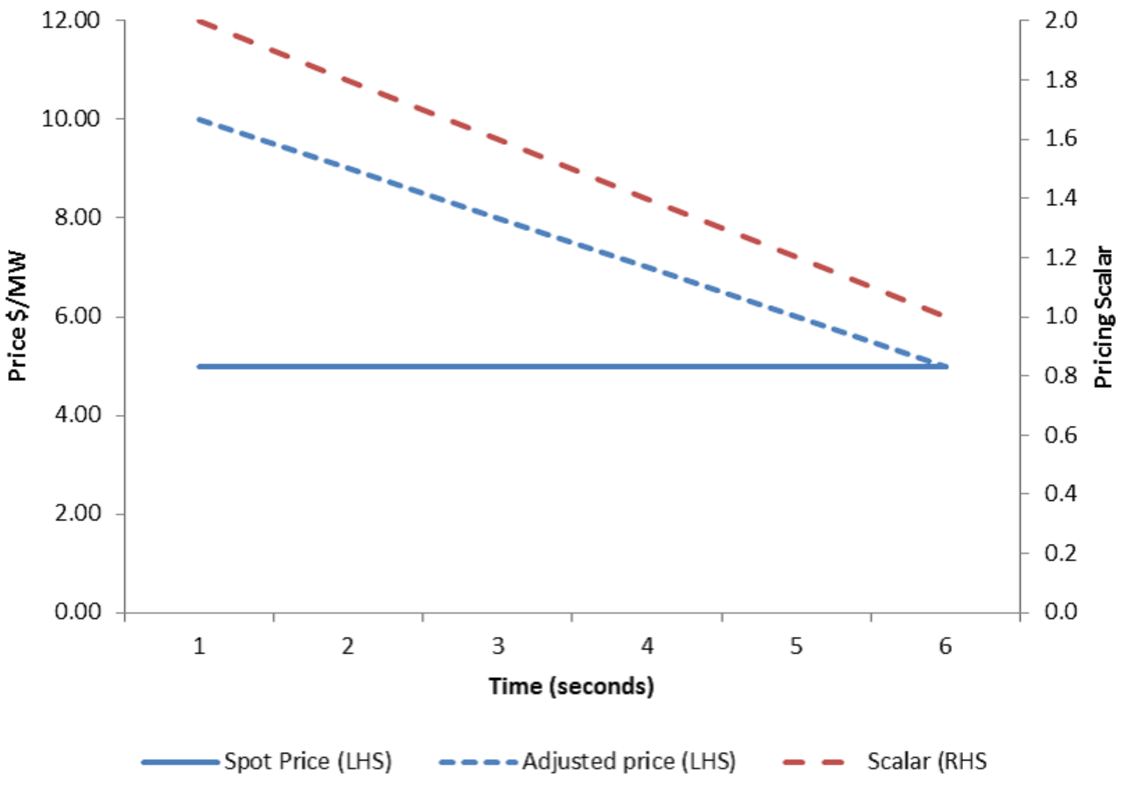
163 DGA Consulting, International Review of Frequency Control Adaptation, 14 October 2016, p. 12.

In reviewing FCAS markets, it is important to reconsider the rationale for the markets that currently exist. To a large extent, the structure of current markets reflects the nature of the generating fleet in existence at the start of the NEM, including factors such as the potential response and duration profile of dominant generating technologies such as steam turbines, hydro and gas turbines.

Emerging changes to the generation fleet could suggest the need for changes to existing FCAS markets such as development of alternative pricing approaches 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 ten second duration, the slow service as a 30 second service with two minutes duration etc.

Alternatively, the pricing of individual services could be moved to some form of differential pricing within existing services. This would involve the application of a time weighted payment profile with each time slice receiving a different weighting. Figure 6.4 shows the application of differential pricing to the six second service as an example. A declining weighting with second "one" would receive X times second "six" with a linear adjustment across the intervening seconds.

Figure 6.4 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:[164]

164 AEMO, submission to the *System security frameworks review* 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 NER 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.

Question 16 Potential options for making changes to FCAS frameworks

What are your views on the above indicative approaches to varying the design of FCAS services, and on other potential changes?

6.4.2 Consideration of the technical characteristics of emerging sources of FCAS

Any decision to redefine the existing FCAS markets will need to take into account the abilities of different potential sources of FCAS to meet the technical requirements of each service. For example, an extended duration requirement for an FFR service may preclude wind farms participating on anything other than a pre-curtailment basis.

The changing capability of the generation fleet suggests a need to integrate alternative energy sources into FCAS markets. An example of this research is the AEMO, ARENA and Hornsdale Stage 2 Wind Farm Australia-first trial starting from October 2017 to test how FCAS could be provided by wind farms in the Australian electricity market. The trial will take place on the 100MW Hornsdale Stage 2 Wind Farm, owned and operated by French renewable energy producer Neoen and international infrastructure investor John Laing in South Australia.[165]

The technical basis of the trial is to test the ability of wind farms to participate in the regulation FCAS market through pre-curtailment of output. That is, to reduce output below the current technical limit set by the generator capacity and prevailing wind resource so as to provide head room to increase output by an agreed amount in response to AEMO instructions via the AGC system. This approach is separate from the concept of utilising the energy embodied in the rotating mass of the turbine to provide short term fast frequency response. This is often termed 'synthetic inertia' and can provide a six to ten per cent power boost for up to ten seconds without any pre-curtailment. However, this limited duration means that wind farm synthetic inertia cannot meaningfully participate in the current fast raise and lower FCAS markets.

165 The project is jointly funded by Neoen and ARENA with an overall budget of $600,000.

The successful completion of a capability demonstration and registration for FCAS in accordance with the MASS will be followed by a market trial, where for 48 hours the wind farm will be participating in the electricity and FCAS markets. The trial intends to demonstrate that the wind turbines at Hornsdale Stage 2 Wind Farm can be efficiently controlled via AEMO's market systems to address changes in power system frequency.

It is expected that the results of the trial will allow AEMO to assess modifications to wind forecasting, bidding and energy management systems required to reduce barriers to entry for FCAS from grid-connected wind and solar farms in Australia. The trial has the potential to demonstrate to the market and investors that wind farms are able to supply FCAS and be fully integrated into the NEM.

The capability of wind farms to provide frequency control services has been trialled in other jurisdictions. In Quebec, wind turbine generators have been required to respond to frequency fluctuations since 2006. The AEMC is currently considering a rule change request lodged by AEMO in August 2017 related to generator technical requirements. The rule change request seeks to mandate requirements for new generators to have active power management capabilities that will enable them to operate within whatever future frequency control frameworks are implemented in the NEM.[166]

Question 17 Technical characteristics of emerging sources of FCAS

What other emerging sources of FCAS should the Commission be aware of?

6.4.3 Managing the frequency impacts of variability under the existing framework

The frequency impacts of variations in non-dispatchable capacity within five minute dispatch intervals that create imbalances in supply and demand is currently managed through the provision of regulating FCAS. Regulating FCAS is described in section 2.4.

AEMO's 2016 *National transmission network development plan* (NTNDP) notes that with continued growth in non-dispatchable capacity, the size and number of continuous minor supply demand imbalances is expected to grow.[167] AEMO considers this would mean more regulation FCAS may be required in future to manage increasing system variability and uncertainty.

AEMO notes that regulating and contingency FCAS have historically been sourced from synchronous generation.[168] If synchronous generation is displaced from dispatch (either permanently or temporarily), the level of FCAS it provided will have to be procured from other sources. As more non-dispatchable capacity enters the market, the dual effect of increased need for FCAS and reduced supply could lead to shortfalls in

166 AEMO, Generator technical requirements, rule change request, August 2017, p. 50.

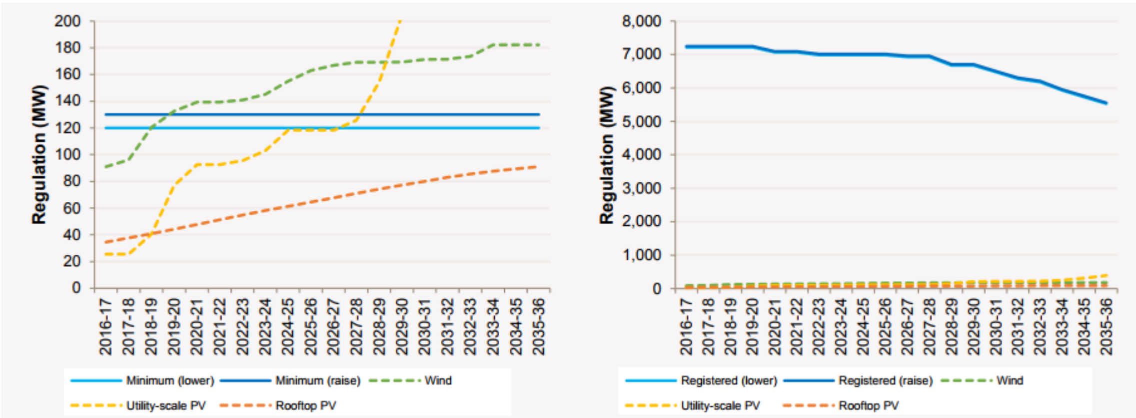
167 AEMO, *National transmission network development plan*, December 2016, p. 61. Note AEMO is only referring in the NTNDP to semi-scheduled and non-scheduled generation, and rooftop solar PV.

168 Ibid.

the provision of regulating FCAS over time. A trial of the provision of regulating FCAS from non-synchronous sources is currently being undertaken at the Hornsdale stage 2 wind farm in South Australia. This is discussed further in section 6.4.2. EnerNOC, a demand response provider, was registered by AEMO in August 2017 as the first Market Ancillary Service Provider and is providing contingency FCAS. This is discussed further in section 7.3.2.

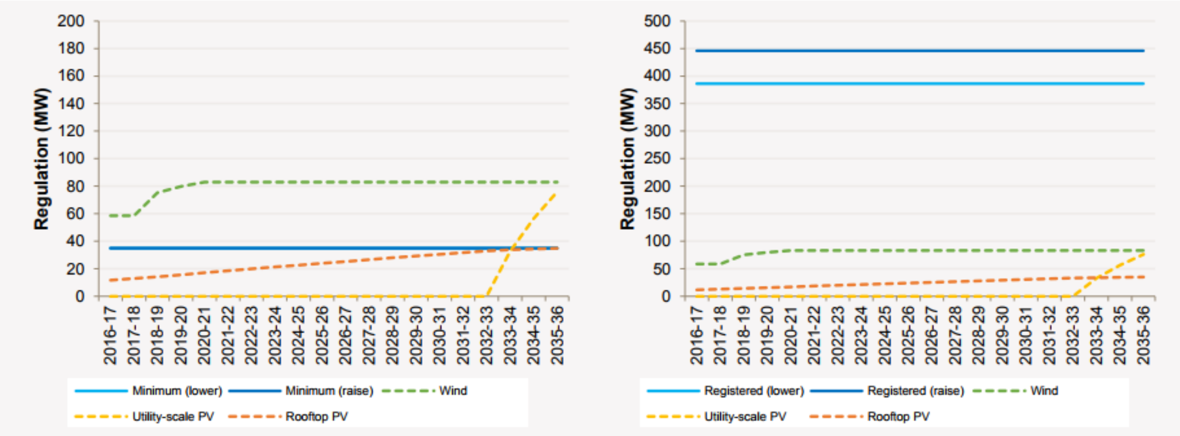
AEMO has projected over the 20 year time horizon of the NTNDP the required NEM-wide levels of regulating FCAS (Figure 6.5, left), highlighting the estimated future regulating FCAS needs associated with the variability of non-dispatchable capacity (that is, utility scale solar PV, wind and rooftop PV, and does not include home energy management systems or batteries). These requirements are compared with the minimum amount of regulation FCAS enabled at present, at any given time (blue lines). Points where dotted lines are above either of the blue lines represent points where regulation FCAS requirements of the corresponding non-dispatchable generation are projected to exceed the minimum amount enabled at present. Figure 6.8 (right) also shows the projected registered supply of FCAS providers over the same period compared to the projected level of regulation FCAS requirements from non-dispatchable capacity.

Figure 6.5 Projected NEM-wide regulating FCAS requirements and registered capacity



AEMO conducted the same analysis for the South Australian region. The results are shown in Figure 6.6 below.

Figure 6.6 **Projected South Australian regulating FCAS requirements and registered capacity**



It is important to note that for both South Australia and NEM-wide, there appears to be sufficient total registered capacity at present to meet regulating FCAS requirements for the projected period to 2036.

However, based on AEMO's analysis, it appears that across the NEM and in South Australia the minimum level of regulating FCAS enabled *at present* may not at all times be sufficient to account for the variability of non-dispatchable capacity into the future. AEMO would therefore need to enable greater than the minimum levels to account for the increasing penetration of non-dispatchable capacity over time, though Figures 3.8 and 3.9 suggest that there is sufficient regulation FCAS capacity to increase the minimum level available. Note the figures presented above are absolute and not cumulative for each technology type, meaning that a coincidence between variation in wind output and variation in utility scale or rooftop solar PV output could necessitate the enablement of more than the minimum level of regulating FCAS. Note also that this analysis does not consider the variability of demand, which is expected to grow over time.

There is a dynamic relationship between the frameworks for forecasting non-dispatchable capacity and the scale and number of resulting imbalances in supply and demand. Improved forecasting of the output from non-dispatchable capacity would result in fewer and smaller imbalances in supply and demand. Over time, the inclusion of accurate forecasting of demand would have the same effect. This would also put downward pressure on the levels of FCAS required to be enabled.

The AEMC is seeking views on options to manage the frequency impacts of the variability in non-dispatchable capacity within the five minute dispatch interval.

Question 18 **Managing the frequency impacts of non-dispatchable capacity**

(a) **Is the existing FCAS framework sufficient to maintain frequency as greater proportions of non-dispatchable capacity enter the power system?**

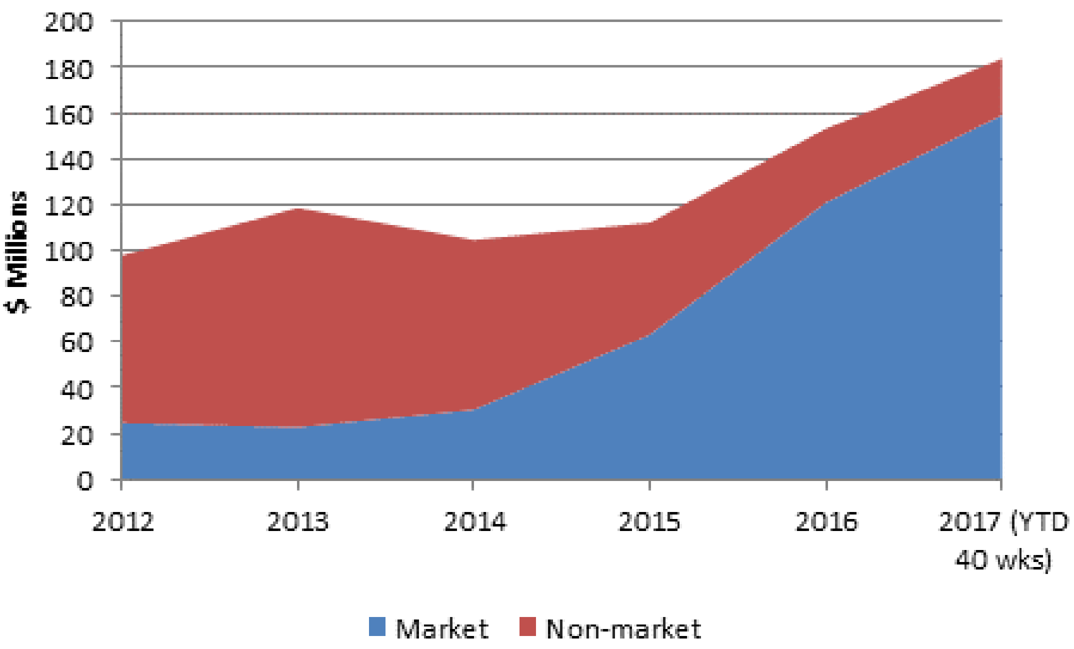
(b) **Would it be more efficient to improve the forecasting of non-dispatchable capacity to reduce imbalances in supply and demand, or to rely on higher levels of regulating FCAS to manage those imbalances?**

(c) **What other efficient options are there to manage imbalances in supply and demand resulting from the variability of non-dispatchable capacity within the five minute dispatch interval?**

6.5 FCAS cost recovery

As explained in section 3.1.3, the cost of market ancillary services has progressively increased, both as a share of the total cost of ancillary services and in absolute terms, from roughly 25 per cent or nearly $25 million in 2012 to a year to date (40 weeks) value of 87 per cent or $159 million in 2017, as shown in Figure 6.7.

Figure 6.7 Cost of market and non-market ancillary services 2012 to 2017 (40 wks part year)



As set out in Figure 3.1, regulation ancillary services have increased significantly, both in absolute and percentage terms (at $78 million or 1600 per cent) compared to $57 million or around 290 per cent for contingency ancillary service costs. By 2017, the annual cost of regulation and contingency ancillary services were roughly equivalent. As such, the cost recovery mechanism is equally important for both these classes of ancillary services.

As noted above, the payment for the provision of market ancillary services is based on the market clearing price and the quantity of service enabled. However, the recovery of the cost of market ancillary services varies depending on the particular service. Table 6.1 summarises the cost recovery approach.[169]

Table 6.1 Ancillary service cost recovery method

Ancillary service	Recovery method	Recovered from
Regulation FCAS	Causer pays basis	Market participants with Market Participation Factor (MPF) and residual from market customers
Contingency FCAS	Recovered in proportion to energy consumption / generation	Raise services are recovered from generators; lower services are recovered from market customers

The aim of cost recovery is to provide a price signal that incentivises market participants to act in a way that minimises the need to procure these services. In order to succeed in this aim, a cost recovery framework needs to transparently and accurately map cost recovery to actions that create the need for the services.

With respect to the causer pays arrangements applied to the recovery of regulation FCAS costs, there does not appear to be a clear linkage between behaviour and cost recovery. The key drivers of cost recovery for regulation FCAS are contribution factors calculated for each market participant. These factors are designed to represent the deviation from a reference trajectory derived from expected dispatch or expected MW consumption. The deviations are calculated every four seconds and averaged over a dispatch interval. The average results are referred to as 5-minute factors with contribution factors determined based on 28 days of 5-minute factors. These contribution factors are then applied for the next 28 days to calculate regulation FCAS cost recovery.

The result of this arrangement is to both mute the price signal in any single dispatch interval due to the 28 day averaging and to create an inter-temporal disconnect due to the measured historic behaviour being used as the basis for recouping future costs which have an unknown magnitude (as they will be an outworking of future regulation FCAS bids). This has the potential to encourage unintended behaviour such as changes to generator governor controls that may undermine the effectiveness of the NEM frequency control framework. This is discussed further in chapter 5.

AEMO is currently undertaking a review of the regulation ancillary service causer pays procedure that has involved extensive public consultation.[170] The AEMC understands that a draft report and determination will be released in mid-November 2017. The outcomes of this work will be a critical input into refining this review and the AEMC

169 See: AEMO, Settlements guide to ancillary services payment and recovery, July 2015.

170 See: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Causer-Pays-Procedure-Consultation

does not want to pre-empt the findings (or duplicate the work). As such, we intend to undertake a watching brief on regulation FCAS cost recovery.

In contrast, contingency service costs are recovered from market participants on the basis of each participant's share of total energy in the relevant five minute period. This can be either through local recovery, based on the region in which the requirement occurred, or global recovery across the entire NEM.

This approach has the benefit of reflecting real time market participation and as such provides an alignment between when an action occurs and the calculation of the financial impact in terms of the cost of purchasing contingency services. However, the current approach does not capture the extent to which a participant contributed to setting the contingency size and therefore the total level of services required to be sourced. For example, the Kogan Creek power station is a single 750 MW unit which will generally be the largest unit in the NEM and therefore set the prevailing contingency size. Yet a small generator not impacting on the level of contingency service required will pay the same (in $MW terms) as the owner of Kogan Creek.

Question 19 Cost recovery arrangements

(a) Do you consider existing cost recovery arrangements for contingency FCAS to be appropriate?

(b) If not, how should cost recovery arrangements be changed?

6.6 Co-optimisation with other markets

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 minimum levels of inertia already being implemented are predominately targeted at addressing the risk associated with network separation or islanding, 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. Consideration will also need to be given to potential interaction with other system characteristics such as system strength and stability.

This presents considerable technical complexities given that system inertia is provided by synchronous generators (that is, non-inverter connected generators) that are currently operating and synchronised with the network. As such, inertia is effectively provided on a binary basis, that is, an entire generating unit's inertia is either online or offline and the speed at which that inertia can be brought online reflects the start and synchronisation time of each generating unit. As high inertia units are invariably steam turbines with long start times, in practical terms, this is likely to require day ahead commitment for the provision of an inertia service.

As such, there are significant technical and regulatory issues that will need to be addressed in order to deliver a co-optimised solution, suggesting the potential need for an extended development timeframe.

Question 20 Co-optimisation with other markets

(a) Are there other system services, such as inertia, system strength or system stability, that should be co-optimised with FCAS markets?

(b) If so, can one service (such as inertia) be optimised first and, if so, why?

(c) Would co-optimisation impact on cost recovery and, if so, how?

7 Distributed energy resources participation in system security frameworks

The Finkel Panel Review, published in June 2017, noted that AEMO's ability to address the technical and system security impacts of distributed energy resources is affected by "outdated connection standards and control mechanisms" and that "with appropriate communications infrastructure, standards and aggregation mechanisms in place, distributed energy resources can provide significant opportunities to improve power system security".[171] The report recommends that the AEMC "review the regulatory framework for power system security in respect of distributed energy resources, and develop rule changes to better incentivise and orchestrate distributed energy resources to provide essential security services such as frequency and voltage control."

The potential for distributed energy resources to support power system security has also been recognised by AEMO through its Future Power System Security work program, the AEMC in the final report of its *Distribution market model* project and Energy Networks Australia in its *Electricity network transformation roadmap*.[172] However, there has been no detailed consideration of how this could occur in a technical or regulatory sense.

The *Frequency control frameworks review* provides the means by which the AEMC and stakeholders can explore this issue further.

7.1 Background

This section provides an overview of the services that are required to maintain power system security, the drivers for consideration of distributed energy resources in system security frameworks and the ways in which distributed energy resources could provide system security services.

7.1.1 What are distributed energy resources?

Distributed energy resources do not have a universally agreed upon definition; however, it is generally a term used to describe small-scale sources of energy connected to a distribution network, such as residential solar PV systems, batteries and electric vehicles.

171 Independent Review into the Future Security of the National Electricity Market, final report, June 2017, pp. 62-63.

172 See: AEMO, *Visibility of distributed energy resources*, January 2017, p. 17; AEMC, *Distribution market model*, final report, p. 72; Energy Networks Australia / CSIRO, *Electricity network transformation roadmap*, final report, April 2017, pp. 52-63.

The term is used in this issues paper to describe "an integrated system of energy equipment that is connected to the distribution network."[173] It includes any distribution-connected resource that is able to change its active or reactive power output in a short time frame.[174] This can include:

- 'passive' solar PV systems that only generate power when the sun is shining and generally do not have the capability to change operation in response to an external signal, e.g. a price signal
- 'smart' solar PV systems, including those that are coupled with storage, that are able to change their operation in response to external signals
- stand-alone energy storage such as batteries
- responsive load and short term demand management.

For the purpose of this issues paper, distributed energy resources are considered not to include:

- any embedded generating unit[175] for which someone is registered as a NEM participant
- long term changes to consumption such as energy efficiency or changes in consumption patterns.

This review will focus on distributed energy resources that connect under Chapter 5A of the NER,[176] and systems to which Australian Standard (AS) 4777 apply.[177] When referring to embedded generators, it will primarily focus on micro embedded generator connections.[178]

When referring to distributed energy resources this includes consideration of demand response within the distribution network that could provide power system security

173 This is the definition of distributed energy resource that was used in the AEMC's *Distribution market model* project. See: http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model

174 Active power is a measure of the instantaneous rate at which electrical energy is consumed, generated or transmitted. It is measured in megawatts (MW). Reactive power, which is different to active power, is a necessary component of AC power systems. It is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as AC generators, capacitors and synchronous condensors. Management of reactive power is necessary to ensure network voltage levels remain within required limits, which is in turn essential for maintaining power system security and reliability. It is measured in MVAr (1,000,000 volt-amperes reactive).

175 Embedded generating unit is defined in Chapter 10 of the NER as a generating unit connected within a distribution network and not having direct access to the transmission network.

176 Parties who connect under Chapter 5A of the NER include retail customers and non-registered embedded generators.

177 AS 4777 is the Australian standard for grid connections of energy systems via an inverter.

178 The term 'micro EG connection' is defined in Chapter 5A of the NER as "a connection between an embedded generating unit and a distribution network of the kind contemplated by AS 4777".

services. Demand response could include rapid changes in consumption that could be used to assist with the management of power system frequency or voltage. The role of demand response in wholesale markets and reliability is being considered in the AEMC's *Reliability frameworks review*.[179]

7.1.2 What are system security services?

The NER defines a number of system standards that the power system must be operated within for it to be in a satisfactory operating state.[180] The power system is defined as being in a satisfactory operating state when these standards are met,[181] including:

- **Frequency** - frequency is within the limits in the frequency operating standard.[182]
- **Voltage** - the voltage magnitudes are within the limits set in schedule 5.1 of the NER.
- **Current** - current flows are within the ratings of transmission lines.
- **System stability** - the power system should remain in synchronism and be stable in line with S5.1a.3 of the NER.

In addition to these system standards is the system restart standard. The system restart standard specifies the parameters for restoring generation and transmission system operations after a major supply disruption including a black system event (black out).

System security services broadly refer to those non-energy services that are used to manage power system security. These services maintain key technical characteristics of the power system, including by helping to meet the above standards.

System security services have historically been provided by either:

- procurement through a market, where service providers submit bids for the service and are centrally dispatched (e.g. frequency control ancillary services, see section 2.4.2)
- procurement through a tender process run by AEMO (e.g. system restart ancillary services)[183]

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179 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Frameworks-Review

180 To be in a secure operating state, the power system must be in a satisfactory operating state and able to be returned to a satisfactory operating state following a credible contingency.

181 See clause 4.2.2 of the NER.

182 See section 2.4.2.

183 System restart ancillary services (SRAS) are described in more detail here: https://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.ashx

- procurement as network support and control ancillary service (NSCAS) by either a TNSP or AEMO[184]
- as an obligation imposed through generator performance standards (e.g. the automatic access standard for generating system response to disturbances following contingency events set out in S5.2.5.5 of the NER)
- central direction from AEMO.[185]

As the needs of the power system evolve and the generation fleet changes, the required services needed to maintain system security are also likely to evolve. For example, AEMO has recently implemented a schedule which allows AEMO to dispatch reactive power from participants to assist with voltage control. This schedule aims to provide AEMO and reactive plant operators with the ability to manage networks in an operational environment, assisting with maintaining the power system within a secure operating state.[186]

Technically, distributed energy resources may be able to provide services that can assist with meeting all of these standards. However, there may be reasons why distributed energy resources have been unable to participate in the procurement processes outlined above. There may also be a number of reasons, including regulatory, technical and commercial reasons, why distributed energy resources do not currently play a large role in providing system security services. These reasons are explored in more detail below.

7.1.3 Why are distributed energy resources being considered?

The generation fleet in the NEM is transitioning from a relatively small number of large, transmission-connected synchronous generators to larger numbers of smaller generating units such as utility-scale solar PV and wind. These units are increasingly connecting to the distribution network. In addition, a formerly passive demand side is becoming increasingly engaged in energy markets through the uptake of residential solar PV, batteries and demand response. Figure 7.1 shows Bloomberg New Energy

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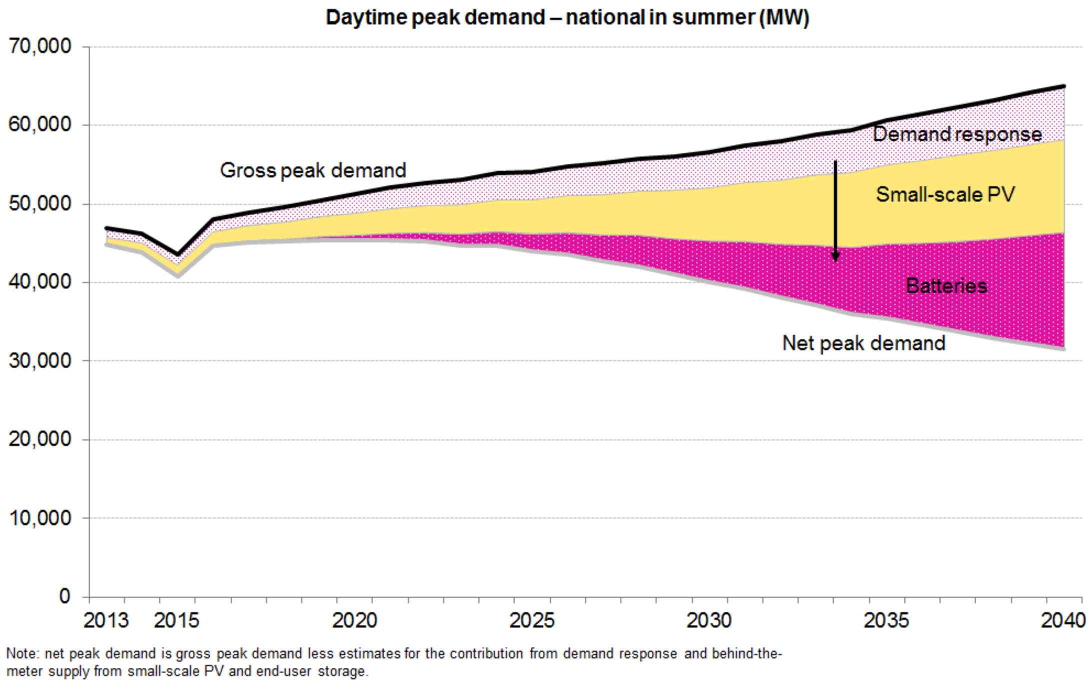
184 NSCAS can be divided into three categories: voltage control ancillary services (VCAS) to control the voltage at different points of the electrical network to within the prescribed standards, network loading control ancillary services (NLCAS) to control the power flow on network elements to within the physical limitations of those elements, and transient and oscillatory stability ancillary services (TOSAS) to maintain transient and oscillatory stability within the power system following major power system events. These services are described in more detail here: https://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.ashx The AEMC notes that the majority of NSCAS procured to date has been for the purposes of controlling voltage.

185 Under clause 4.8.9(a)(1) of the NER, AEMO may require a registered participant to do any act or thing if AEMO is satisfied that it is necessary to do so to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state.

186 More information on the reactive power dispatch schedule system is available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Dispatch-information/VAr-dispatch

Finance's forecast of the capacity of demand response, small-scale solar PV and batteries relative to national aggregate peak demand out to 2040.

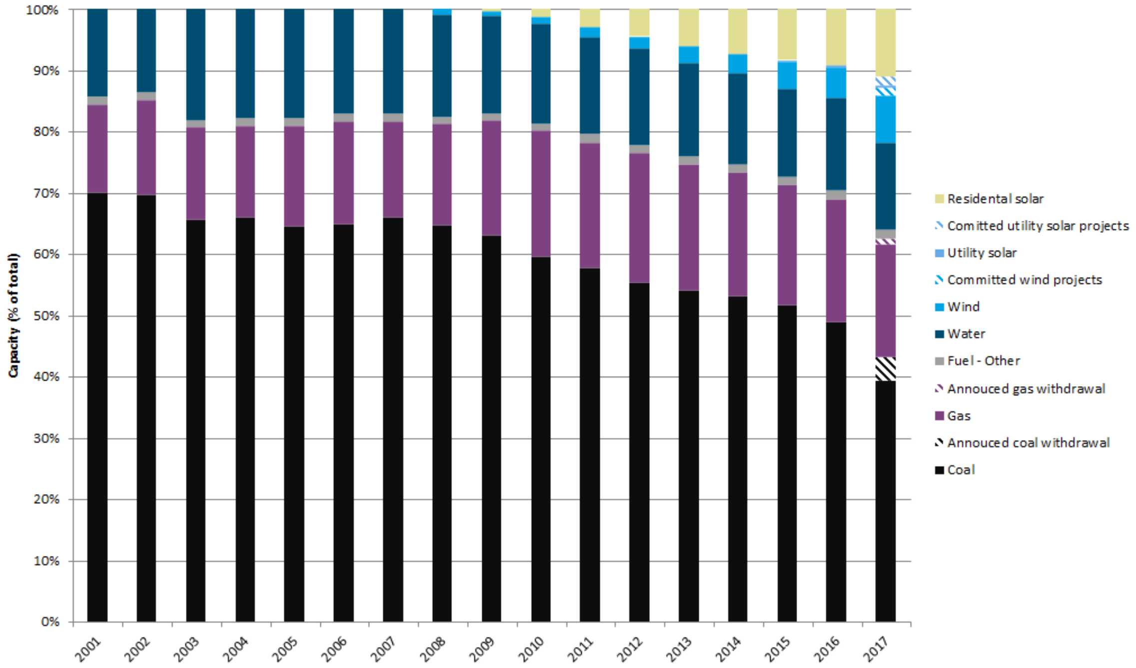
Figure 7.1 Forecast demand response, small-scale solar PV and battery capacity relative to daytime peak demand



Source: Bloomberg New Energy Finance, New Energy Outlook 2016.

Many of the system services required for the secure operation of the power system have been provided by large, synchronous centralised generators; often as a by-product when producing energy. As these generators retire, there is the need to maintain the provision of these services. Figure 7.2 shows the changing generation mix in the NEM since 2001.

Figure 7.2 Changes in NEM generation capacity by percentage of total



Sources: AEMO, *Electricity statement of opportunity reports* from 2001 - 2016. AEMO, *Generation information page*, accessed 25 July 2017. Clean Energy Regulator, *Postcode data for small-scale installations*, accessed 25 July 2017.

It is possible that distributed energy resources may be needed to participate in the provision of system security services. This need could become particularly acute in regions where the output of distributed energy resources are reducing minimum operational demand,[187] which consequently reduces the amount of generation provided through central dispatch.

The last resort for maintaining power system frequency following a large generator trip is to shed load using under frequency load shedding (UFLS).[188] However, the effectiveness of UFLS could decrease in regions with high penetration of small-scale generation such as rooftop solar PV. This is because UFLS works by disconnecting distribution-connected load to reduce demand. As more residential and small business loads are coupled with generation, effective demand from the grid is reduced. During periods of high output from these systems, distribution network feeders that are selected to be tripped by UFLS could have a lower impact on an under frequency condition if they have high PV penetration, resulting in UFLS shedding more distribution feeders to arrest the frequency deviation, i.e. more customer load would be disconnected.[189] This degradation of UFLS effectiveness in preserving system

187 Operational demand refers to electricity used by residential, commercial and large industrial consumers, as supplied by scheduled, semi-scheduled and significant non-scheduled generating units. It does not include demand met by residential PV.

188 UFLS is an emergency frequency control scheme, which are discussed in section 2.4.4.

189 This issue is discussed in AEMO's future power system security work stream. See: AEMO, *Visibility of distributed energy resources*, January 2017, pp. 32-33.

frequency is another driver for considering the incorporation of distributed energy resources into frequency control frameworks.

AEMO has been exploring these issues through its Future Power System Security work program, and notes that if the uptake of distributed energy resources is not "holistically managed", they will "in aggregate, have a material and unpredictable impact on the power system and its dynamics due to their cumulative size and changing characteristics."[190] Some of these impacts include distortion of distribution network voltages, straining the thermal ratings of network equipment and the risk of large volumes of distributed energy resources disconnecting following a power system disturbance.[191]

The Commission considers that it is important for AEMO to look at these issues to support the ongoing secure operation of the power system. However, this review does not focus on ways to mitigate the adverse impacts of distributed energy resources on AEMO's ability to maintain power system security.

This review will focus instead on how the frameworks under which distributed energy resources connect, operate and participate in the NEM can be designed so as to enable the efficient provision of system security services.

7.1.4 What system security services could distributed energy resources provide?

Generally, system security services can be provided by a change in active or reactive power output or consumption. For example, the frequency operating standard is met through the procurement of sources of active power that are able to increase or decrease active power output. Distributed energy resources could assist with the maintenance of power system frequency by increasing active power output or lowering consumption to raise power system frequency, or reducing output or increasing consumption to lower power system frequency.

Other system security services that could be provided by distributed energy resources include:

- reactive power output or consumption to provide voltage support
- inertia or inertia-related services to either participate in a future ancillary service market or procured as a network service by an NSP
- system strength services procured as a network service by an NSP.

These services may be able to be provided at an individual level but are more likely to be provided through aggregation. By aggregating a large number of distributed energy

190 AEMO, *Visibility of distributed energy resources*, January 2017.

191 On 3 March 2017, following the disconnection of a large amount of generation in South Australia, approximately 150MW of residential PV shut off. See: AEMO, Fault at Torrens Island switchyard and loss of multiple generating units on 3 March 2017, March 2017.

resources and controlling service provision, distributed energy resources would be able to have a more material contribution to maintaining power system security. There are other associated benefits of having distributed energy resources aggregated to provide system security services. Aggregation reduces the number of interactions between the buyer of the service (such as AEMO) and the providers. It also allows a single party to be responsible for the collective operation of large numbers of distributed energy resources and manage the risk of the failed operation of some units.

7.2 Existing frameworks for the connection and operation of distributed energy resources

This section provides an overview of the existing regulatory requirements that apply to the connection and use of distributed energy resources, and explores whether these frameworks require the provision of services that can be used to help AEMO maintain power system security.

The existing frameworks for the connection and operation of generation and load to the power system sit in the NER. However, in relation to distributed energy resources that are connected by retail customers or non-registered embedded generators (i.e. those who connect under Chapter 5A of the NER) these frameworks are not prescriptive and to a large degree rely on the discretion of individual DNSPs as well as Australian Standards.

7.2.1 Connection arrangements in the NER

To interact with the network, such as through charging or consumption, a distributed energy resource must be connected to the electricity network. To do so, the person who owns the distributed energy resource must enter into a connection agreement with the local DNSP.

The connection arrangements set out in the NER establish the obligations and processes by which generating systems and loads connect to a transmission or distribution network. Generally, non-registered participants connect under Chapter 5A of the NER.[192] These rules apply (among others) to:

- retail customers
- micro embedded generators (e.g. retail customers with solar PV or battery storage systems)
- non-registered embedded generators (connecting a system of less than 5 MW but larger than a micro embedded generator).

There are three types of connection services defined under Chapter 5A:

192 Non-registered embedded generators may opt to connect under the process outlined in rule 5.3A of the NER. See clause 5A.A.2 of the NER.

1. **Basic connection services**: These services are not defined in detail, but largely cover the majority of simple connections by retail customers (including micro embedded generator connections).[193]

2. **Standard connection services**: These services are connection services that DNSPs can develop a standing offer for but aren't covered by the basic connection service definition.[194]

3. **Negotiated connection services**: these cover the connection of anything for which a standing offer doesn't exist, or if the customer elects to negotiate the terms and conditions of its connection.

Chapter 5A does not contain any specific requirements or guidance on the actual technical specifications of connections by retail customers to distribution networks, either with a generating system (such as a solar PV system) or without. Rather, it contains broad requirements that the terms and conditions of model standing offers or negotiations for connection services must, for example, cover "the safety and technical requirements to be complied with by the retail customer".[195] The exception is that micro-embedded generation is defined in the NER by reference to AS 4777 (discussed below).

This can be contrasted against the arrangements for connections under Chapter 5 of the NER. Chapter 5 covers the connection of registered participants connecting to distribution and transmission networks. When a registered participant connects equipment to the network under Chapter 5, it must register performance standards for that plant that clearly set out the technical capability of the plant. Under this framework:

- Access standards in the NER define the range of the technical requirements for the operation of equipment. These standards are negotiated during the process for the connection of generators, market network service providers and certain end use customers. These access standards include a range from the minimum to the automatic access standard.

- For each technical requirement defined by the access standards a connection applicant must either:

  - meet the automatic access standard, in which case the equipment will not be denied access because of that technical requirement, or

193 For example, Energex consider basic connection services encompass connections of load for most retail customers and connection of micro embedded generators up to 5kW, where no network augmentation is required.

194 For example, Energex's standard connection services include unmetered connections, e.g. street lighting.

195 See Clause 5A.B.2(b)(4) of the NER.

— negotiate a standard of performance with the local NSP (and AEMO for any access standards that are AEMO advisory matters) that is at or above the minimum access standard and below the automatic access standard.

- Equipment that does not at least meet the minimum access standard will be denied access to the network because of that technical requirement.

The access standards for generating systems cover a range of technical capabilities, including reactive power capability, quality of electricity, response to frequency and voltage disturbances during and following contingency events, frequency control, protection systems, and monitoring and control systems. This provides parties connecting under Chapter 5 with a transparent process for establishing the technical requirements of that connection. These performance standards assist AEMO in maintaining the power system in a safe and secure operating state, as well as assisting NSPs in meeting their obligations under the NER.

The Commission is currently considering a rule change request from AEMO seeking to make changes to the access standards for generators connecting under Chapter 5 of the NER.[196] AEMO considers that the current access standard settings in the NER and the negotiating framework to set performance standards are not adequate to ensure ongoing security in an evolving power system. The rule change request proposes to:

- amend or introducing a number of access standards for connecting generators, including those relating to voltage control and reactive power provision, disturbance ride through, system strength, active power control and remote monitoring and control

- amend the process for negotiating performance standards

- implement transitional arrangements applying the changes to any performance standards agreed on or after 11 August 2017.

AEMO has also proposed to amend the size threshold for certain access standards. This amendment would remove the requirement for certain access standards to only apply to generators larger than 30MW. While AEMO suggest this would address some system security issues caused by generators rated at less than 30MW, it would not extend to generators that connect under Chapter 5A. For this reason, the rule change request does not directly impact the technical requirements for generators connecting under Chapter 5A.

As set out above, there are no detailed technical requirements in the NER for the connection or operation of distributed energy resources that connect under Chapter 5A.

196 See: http://www.aemc.gov.au/Rule-Changes/Generator-technical-performance-standards

Question 21 Consistency in the provision of system security services

To what extent is it important that the NER arrangements for the provision of system security services are consistent between providers of such services, e.g. large, transmission-connected generators and distributed energy resources?

Individual DNSP connection arrangements

As the NER is not highly prescriptive regarding the technical aspects of connections under Chapter 5A, a significant amount of discretion lies with the DNSP. The rapid, and often concentrated, uptake of distributed energy resources has resulted in certain DNSPs requiring distributed energy resources to meet certain technical parameters. However, the AEMC understands that these requirements are not consistent between DNSPs and have led to different approaches to distributed energy resources depending on the location of its connection. This issue was discussed further in the final report of the AEMC's *Distribution market model* project.[197]

The Queensland DNSPs have developed a joint connection standard containing detailed technical requirements and performance standards to "provide proponents of micro embedded generating units information about their obligations for connection to and interfacing with the Ergon Energy or Energex networks".[198] This was driven by very high uptake of residential PV in south-east Queensland. These standards place certain obligations on distributed energy resources connected to these networks that assist with maintaining the distribution network within its technical limits. This includes assisting with voltage control and relieving thermal constraints.

For small scale generation (rated less than 30kVA), the connection standard outlines a range of inverter settings that the inverter must be able to operate within, and the set points at which the inverter must trip.[199] It requires inverters to provide reactive power support to the network by either operating at a fixed power factor (0.9 lagging) or to vary power factor with network voltages. The connection standard requires the inverter export limits and over-voltage trip settings to meet the DNSP's requirements.

Although not mandatory for all connections to Ergon and Energex's networks, some inverters may be required to be able to have various operational modes. These modes are:

- disconnect
- do not consume power

197 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model

198 See: https://www.ergon.com.au/__data/assets/pdf_file/0005/198698/STNW1170-Connection-Standa

199 Residential solar PV and batteries need to be coupled with an inverter. This inverter converts DC power - the form of power that is output by batteries and solar PV - to AC power which is used throughout a home and can be exported into the power grid.

- increase consumption
- do not generate power
- increase power generation.

These services are not necessarily required by Ergon/Energex for power system security purposes. Instead, they assist Ergon/Energex in maintaining distribution equipment safely within voltage and thermal limits. However, these functions could be used to maintain power system security.

7.2.2 Australian standard 4777

Australian standard (AS) 4777 applies to low voltage inverters connected to the power system.[200] This applies to grid-connected PV inverters and inverters for energy storage systems, i.e. batteries. Australian standards are non-binding unless enforced through a separate piece of legislation. The standard is not binding; however, the term micro-embedded generator is defined in the NER with reference to the standard. Several DNSPs, including Ausgrid, Energex and Ergon Energy, refer to AS 4777 in their connection arrangements for small scale embedded generation.

Current version of the standard

The standard was revised in 2015 and applied from 9 October 2016. The revised standard aims to assist in mitigating the impacts of large numbers of inverter connected generators on the distribution network, as well as providing for increased capability from inverters to provide various support services.[201] The revised standard does not require existing systems to be retrofitted to comply with the new standard.

Since the commencement of the new standard, 0.7GW of small scale PV has been installed. This is in addition to approximately 5.3GW of small scale solar PV that was connected prior to the commencement of the standard.[202]

To comply with AS 4777, inverter connected energy systems are required to have the capability to provide a number of services. The provision of the majority of these services is not mandatory. These services are discussed below.

Demand response modes

The revised standard has introduced a series of demand response modes that inverter connected energy systems should be able to operate in. These modes can require the

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200 The standard applies to inverters up to 200kVA connected to low voltage parts of the grid.

201 Standards Australia, *Grid connection of energy system via inverters*, 2016.

202 This data refers to solar PV that is rated up to 100kW. Clean energy Regulator, *Postcode data for small-scale installations*, 20 September 2017, available at http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations

inverters to operate a range of power outputs and inputs. Only one of the modes is compulsory - inverters must be able to disconnect when given a remote signal.

The standard recommends that inverters have the capability to provide the other modes but it is up to the DNSP to decide which modes it requires to be enabled.

The inverter also is required to have the means of connecting to a 'demand response enabling device'. This device does not necessarily have to accompany the inverter unless required by the DNSP. If an inverter is coupled with a demand response enabling device, it must be able to detect and initiate a response to supported demand response modes within two seconds. Any party may be responsible for sending external signals to the inverter. These parties could include the DNSP, the retailer or a third party aggregator. However, it may be the case that any party that is able to send remote signals to the inverter would need to have some form of relationship with the DNSP as this could have an impact of the quality of power supplied within that DNSP's network.

These demand response modes would be able to assist the DNSP in managing voltage and thermal limits within its network. The modes would also be able to assist aggregators in providing system security services, including frequency control, with distributed energy resources.

Power quality response modes

AS 4777 also provides for inverters to have various operating modes that would assist with maintaining power quality at the connection point and for the grid. Not all of these modes have to be enabled to comply with the standard. The power quality response modes covered by the standard include a volt response mode which varies output of the inverter to respond to abnormal voltages.

These modes would be able to be employed to assist DNSPs in managing voltages on their networks. Additionally, they may, through aggregation, be able to be used to provide reactive power support to the power system to assist with maintaining power system security.

The standard also requires inverters to have a range of protective functions. These functions set a range of frequency in which the inverter should be able to operate while also requiring inverters to disconnect when frequency exceeds these limits. If the power system frequency leaves the range of 47Hz-52Hz, the inverter must disconnect.[203]This is the range of frequencies within which the power system frequency should remain following a multiple contingency event in order to meet the frequency operating standard.

203 This range is set to mitigate detrimental impacts on the inverter for frequency disturbances. The disconnection of distributed energy resources at low frequency may exacerbate issues with power system frequency; however, this is consistent with the disconnection of other generating systems in the NEM at low frequencies to prevent plant damage.

Additionally, the standard requires inverter output to decrease as frequency increases above 50.25Hz. Output should linearly decrease as frequency increases. Equally, if there is energy storage available behind the inverter, any energy imports should linearly decrease as frequency decreases from 49.75Hz.

These functions would assist in maintaining power system frequency by reducing power output for over-frequency events and reducing power intake for under-frequency events.

Previous version of the standard

A large amount of existing distributed energy resources were connected before this version of AS 4777 commenced. The differences between the current standard and the preceding version (which applied from 2005) are:

- the introduction of demand response modes
- generally tighter operational limits
- variable change in output for voltage and frequency excursions
- limits to power ramp rates.

Generally the newer standard requires inverters to have increased capability to provide services that assist with managing grid voltages and power system frequency. The majority of these services are not required to be enabled to comply with the standard; however, a DNSP may require some of the services to be provided in the process of connecting the distributed energy resources. As a result, there may be significant amounts of distributed energy resources that are currently not able to provide a range of power system services. These distributed energy resources may be able to be retrofitted to have this capability. The technical challenges of legacy distributed energy resources are discussed in section 7.4.1.

7.2.3 Opportunities or barriers for distributed energy resources to provide system services under the NER connection arrangements and AS 4777

This section explores whether the regulatory frameworks under which distributed energy resources connect and operate provide opportunities or barriers for the provision of system security services. The technical and commercial opportunities and challenges associated with the participation of distributed energy resources in system security frameworks are discussed in section 7.4.

As explained above, the NER is not highly prescriptive regarding the technical capabilities and operational parameters of distributed energy resources. This is unlike the arrangements for generators connecting under Chapter 5 of the NER, which must meet a series of technical standards that are specified in that chapter. Any technical requirements placed on distributed energy resources are imposed by Australian standards or through a DNSP's connection arrangements.

The technical requirements imposed through these frameworks may result in distributed energy resources having the capability to provide system security services, such as an increase in power in response to a drop in frequency, or voltage support. AS 4777 requires inverter-connected energy systems to have the ability to be remotely controlled. As a result, the standard may enable the capability of large amounts of distributed energy resources to be aggregated to provide system security services such as frequency control or voltage support.

However, the connection arrangements in the NER, AS 4777 and DNSPs' own connection requirements do not appear to provide value or incentivise the provision of system security services by means of distributed energy resources. Instead, these frameworks appear to be in place largely to enable DNSPs to manage local network issues.

To date, distributed energy resources do not appear to be compensated for the provision of these services. It may also be the case that DNSPs, through their connection arrangements, have sole access to services that can be provided by distributed energy resources. While DNSPs may require certain services to be provided by distributed energy resources to maintain the safe and secure operation of their networks, this may compromise or limit distributed energy resources' ability to provide services to other parties, including AEMO as the body responsible for managing power system security.

Further, some of the mandatory requirements in AS 4777 may impede the ability of distributed energy resources to participate in the provision of system security services. For example, limits to ramp rates for distributed energy resources may restrict their ability to provide frequency control services.

To date, distributed energy resources have had a limited role in providing system security services. If this were to change, the obligations imposed through the NER connection arrangements and AS 4777 may hinder increased participation.

Question 22 Frameworks for the connection and operation of distributed energy resources

(a) Do the existing connection frameworks inhibit the ability of the owners of distributed energy resources to provide system security services?

(b) If distributed energy resources are to play a bigger role in supporting power system security, would it be more appropriate for the distributed energy resources to be required to provide system security services, or to be incentivised to provide them?

(c) Are there any other regulatory barriers or opportunities relevant to the provision of system services via distributed energy resources that are not discussed in this section?

7.3 Existing frameworks for distributed energy resources to participate in the NEM

There are existing regulatory frameworks in the NER which aim to facilitate the participation of distributed energy resources in the NEM. The frameworks are discussed below, alongside any possible barriers and opportunities they provide to distributed energy resources in providing system security services.

The technical and commercial opportunities and challenges associated with the participation of distributed energy resources in system security frameworks are discussed in section 7.4.

7.3.1 Small generation aggregator framework

Background

In November 2012 the AEMC made a final determination and final rule on the *Small generation aggregator framework* rule change.[204] The rule commenced on 1 January 2013. The objective of the rule change was to reduce the barriers faced by the owners of small generators to actively participate in the NEM.

The rule created a new category of market participant, the Small Generation Aggregator, who is able to sell the output of multiple small generating units[205] through the NEM without the expense of individually registering each generating unit. The AEMC concluded that this would enable small generating units to have more direct exposure to market prices, and therefore create a more efficient wholesale market.

Under the framework, a person who intends to supply electricity from one or more small generating units to a transmission or distribution system may register as a Small Generation Aggregator.[206] A Small Generation Aggregator must classify one or more small generating units as a market generating unit, each with a separate connection point.[207]

A Small Generation Aggregator is registered with AEMO as such. Once it classifies its small generating unit/s as market generating unit/s, it also becomes a Market Participant registered by AEMO as a Market Small Generation Aggregator. The only Small Generation Aggregator registration category is a Market Small Generation Aggregator.

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204 See: http://www.aemc.gov.au/Rule-Changes/Small-Generation-Aggregator-Framework

205 Small generating unit is defined in Chapter 10 of the NER as "a generating unit with a nameplate rating that is less than 30MW; and which is owned, controlled or operated by a person that AEMO has exempted from requirement to register as a Generator in respect of that generating unit in accordance with clause 2.2.1(c)."

206 See clause 2.3A.1(a) of the NER.

207 See clause 2.3A.1(e) of the NER.

A Market Small Generation Aggregator must:

- sell all sent out generation through the spot market for all market connection points it is financially responsible for[208]
- purchase all electricity supplied through the national grid to the market connection points it is financially responsible for.[209]

As at 7 November 2017, there were ten Market Small Generation Aggregators registered in the NEM.[210]

Opportunities or barriers for distributed energy resources to provide system services under the small generation aggregator framework

This section sets out the regulatory opportunities and barriers for the provision of system security services via distributed energy resources under the small generation aggregator framework.

Provision of market ancillary services

To provide market ancillary services – i.e. FCAS – a generating unit must be classified as an ancillary service generating unit. Under the NER, only Market Generators can apply to AEMO for approval to classify a generating unit as an ancillary service generating unit.[211] The NER places a number of obligations on the Market Generator in relation to the operation of the ancillary service generating units, some of which are civil penalty provisions.

A Market Small Generation Aggregator is, by definition, not a Market Generator (and not a Generator). They are therefore not able to apply to AEMO for approval to classify a small generating unit as an ancillary service generating unit. This means that Market Small Generation Aggregators cannot provide market ancillary services, including FCAS, by means of a small generating unit.

The AEMC reached this conclusion in the final report of the *Integration of storage* project,[212] and recommended that the framework be expanded to allow this to occur.

A rule change would be required to enable a Market Small Generation Aggregator to apply to AEMO for approval to classify and use a small generating unit as an ancillary service generating unit, and to subject these parties to the same set of obligations that apply to Market Generators who own and operate ancillary service generating units.

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208 See clause 2.3A.1(g) of the NER.

209 See clause 2.3A.1(h) of the NER.

210 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists

211 See clause 2.2.6(a) of the NER.

212 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Integration-of-storage

Provision of non-market ancillary services

An NSCAS or SRAS provider is any person who agrees to provide one or more network support and control ancillary services or system restart services to AEMO under an ancillary services agreement.

The NER do not appear to prevent a Market Small Generation Aggregator from tendering or applying to AEMO to provide non-market ancillary services, including NSCAS and SRAS, by way of its generating units.

7.3.2 Ancillary services unbundling

Background

In November 2012 the AEMC made a final determination and final rule on the *Demand response mechanism and ancillary services unbundling* rule change.[213] The objective of the rule change request was to:

- implement a demand response mechanism for the wholesale market
- unbundle the provision of ancillary services from the purchase and sale of electricity.

The AEMC concluded that there were no regulatory barriers to demand side participation in the NEM, and therefore made no rule on the first part of the rule change request.

The AEMC did make a rule to unbundle the provision of ancillary services from the provision of energy. The rule provides for a new type of market participant – a Market Ancillary Service Provider – who can offer appropriately classified ancillary services loads or aggregation of loads into FCAS markets without having to be the customer's retailer.

The AEMC concluded that the final rule would enable a more diverse group of suppliers to provide FCAS, which would enhance competition in FCAS markets and better enable AEMO to manage the frequency of the power system. The rule commenced on 1 July 2017.

The Market Ancillary Service Provider is required to satisfy certain registration requirements, deliver FCAS services in accordance with AEMO's specifications, just as any other market participant is required to do, and submit FCAS offers to the relevant FCAS markets in accordance with the provisions in the NER. AEMO's technical specifications previously prevented regulating FCAS from being provided through the aggregation of loads. AEMO addressed this through its *Review of the market ancillary service specification* and the revised Market Ancillary Service Specification, effective

213 See: http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

from 30 July 2017, sets out the process required for aggregated ancillary service facilities to provide regulating FCAS.[214]

A subsequent rule change request was submitted by AEMO in April 2017. The *Classification of loads as ancillary services loads* rule change, made in August 2017, allows any load to be eligible for classification as an ancillary services load.[215] It removed the restriction that only a market load could be classified by a Market Ancillary Service Provider as an ancillary service load. The rule commenced on 29 August 2017.

There is currently only one party, EnerNOC, registered as a Market Ancillary Service Provider in the NEM.[216] As of October 2017, EnerNOC has started bidding contingency FCAS into the NEM. More detail is provided in Box 7.1.

Box 7.1 EnerNOC providing contingency FCAS

EnerNOC is a provider of energy intelligence software and demand response services, including services that assist with frequency control.

By reducing the consumption of some demand-side loads, EnerNOC has been able to offer frequency raise services in the NEM FCAS markets. These demand-side electricity loads, typically commercial and industrial customers, are able to be communicated with remotely and if needed, turned down.

For EnerNOC to utilise a load for frequency control services, it must install a device that connects to the load and monitors grid frequency. The device will rapidly reduce load following a trigger condition (such as a measurement of low frequency). The disconnection of load assists in arresting the fall in frequency, having the same effect of a rapid increase in generation of the same magnitude.

Following the Commission’s final rule on the Demand response mechanism and ancillary services unbundling rule change request, EnerNOC has registered as a Market Ancillary Service Provider (MASP). EnerNOC has also aggregated a portfolio of demand-side loads that are able to be turned down from a signal to do so. As a registered MASP, EnerNOC is now bidding in FCAS markets by offering a reduction in load. EnerNOC is offering six-second, 60-second and 5-minute raise frequency services. If these contingency services are enabled by AEMO, they may be used following a fall in power system frequency.

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214 See: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Amendment-Of-The-Market-Ancillary-Service-Specification

215 See: http://www.aemc.gov.au/Rule-Changes/Classification-of-loads-as-ancillary-service-loads

216 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists

Opportunities or barriers for distributed energy resources to provide system services under the ancillary services unbundling framework

This section sets out the regulatory opportunities and barriers for the provision of system security services via distributed energy resources under the ancillary services unbundling framework. The technical and commercial opportunities and challenges associated with the participation of distributed energy resources in system security frameworks are discussed in section 7.4.

Provision of market ancillary services

To provide market ancillary services – i.e. FCAS – a load must be classified as an ancillary service load.[217] Under the NER, Market Customers can apply to AEMO for approval to classify a load (market load) as an ancillary service load. As a result of the rule changes set out above, Market Ancillary Service Providers are also able to apply to AEMO for approval to classify a load as an ancillary service load. Market Customers and Market Ancillary Services Providers with ancillary service loads are subject to a number of obligations under the NER regarding the operation of the ancillary service load, some of which are civil penalty provisions.

As a result, there do not appear to be any regulatory barriers to a load, including individual residential and small business loads, from providing FCAS, if it is provided by a Market Customer or Market Ancillary Service Provider.

Provision of non-market ancillary services

An NSCAS or system restart ancillary services (SRAS) provider is any person who agrees to provide one or more NSCAS or SRAS services to AEMO under an ancillary services agreement.

While SRAS is only provided by generators, and NSCAS tends to only be provided by generators or network service providers, the NER do not appear to prevent a Market Ancillary Service Provider from tendering or applying to AEMO to provide non-market ancillary services, including NSCAS and SRAS, by way of the load it has contracts with.[218]

Question 23 Frameworks for distributed energy resources to participate in the NEM

Are there any other regulatory barriers or opportunities relevant to the provision of system services via distributed energy resources that are not discussed in this section?

217 See clause 2.3.1(f) of the NER.

218 The Commission acknowledges that there may be barriers to distributed energy resources providing non-market ancillary services in AEMO guidelines, such as the SRAS guidelines. See: AEMO, *SRAS guidelines*, September 2014.

7.4 Other issues to consider

There may be challenges for the provision of system security services via distributed energy resources that exist outside of the regulatory frameworks set out in the previous sections. Some of these challenges are discussed below.

7.4.1 Technical challenges

While it may be more complex for an aggregator to demonstrate its ability to provide system security services than for the traditional provider (e.g. a market generator), the AEMC considers that it is technically feasible, depending on the aggregated size and capability of the devices, and other technical challenges described below.

Existing network infrastructure

If distributed energy resources provide system services, there needs to be a consideration of any limitations imposed by the network infrastructure where these distributed energy resources are connected. For example, aggregated distributed energy resources may be able to provide an increase in power to counter an under-frequency event; however, this may be constrained by voltage and thermal limits within the distribution network. These constraints are much better understood with respect to transmission networks where they are currently already applied, and can be factored into the dispatch of system security services more easily.

The Commission understands that DNSPs do not have the same level of monitoring capability on their networks as TNSPs do. As a result, it is more difficult for DNSPs to dynamically monitor network capacity. This could result in the DNSP making conservative estimates of network capacity at any given time. As the uptake of distributed energy resources continues, line capacity may become inadequate and may require replacement/upgrades and/or transformer upgrades to cope with increased network loading and voltage fluctuations. Increased bi-directional flows may also require more modern protection systems. As a result, distribution networks may not be able to accommodate system security services provided by distributed energy resources.

Legacy distributed energy resources

There is a significant amount of distributed energy resources connected under legacy Australian Standards and DNSP connection arrangements. Such distributed energy resources may have limited or no ability to communicate remotely or to respond to price signals that incentivise the provision of particular system services. Similarly, these distributed energy resources may not be able to respond to changing network conditions, such as changes in voltage and frequency.

As a result, while there are substantial amounts of distributed energy resources embedded in the power system, not all of it has the technical capability to offer system security services.

These issues may be resolved if the inverter is replaced with one compliant with the new standard, or if there are incentives available that encourage legacy distributed energy resources to upgrade hardware or software.

Sufficient aggregated capability

A sufficient number of distributed energy resources would need to be aggregated to provide system security services in a way that meets AEMO's required need. For example, a considerable number of household batteries would need to be aggregated to enable a single party to offer SRAS to AEMO and for the combined capability of those resources to provide a meaningful service - i.e. to restart the system. While the AEMC considers that it is not technically infeasible for distributed energy resources to provide such services, there are nevertheless likely to be some technical challenges involved in managing the aggregation of these resources in a way that meets AEMO's requirements for the provision of system security services.

An aggregator would also likely need to take into account the 'firmness' of response from the distributed energy resources it has contracted with. This is discussed in the next section.

Speed of response

Certain system security services (e.g. frequency control) require a fast response from distributed energy resources. If distributed energy resources are required to respond an external signal to provide services, this may limit its ability to offer certain services. This may also be an issue with older distributed energy resources which have limited communication capability. Certain inverters may not have the technical capability to change output within a short timeframe.

If distributed energy resources are unable to respond within a short period of time, it may limit the ability to provide certain system security services.

Question 24 Technical challenges

(a) Is the aggregated capability of distributed energy resources sufficiently 'firm' for aggregators to provide the system security services that AEMO needs?

(b) Are there any other technical challenges relevant to the provision of system services via distributed energy resources that are not discussed in this section?

7.4.2 Commercial challenges

There may also be commercial challenges that limit the integration of distributed energy resources into system security frameworks.

Transaction costs

Distributed energy resources serve primarily to provide energy-related services. The key value stream for distributed energy resources to date has been to offset electricity costs for consumers, either through generating power onsite or using storage to maximise PV output or shift grid electricity consumption to cheaper periods. Residential and small business consumers have historically not used their distributed energy resources to capture the value of providing ancillary services, such as frequency control, to AEMO. As a result, distributed energy resource owners may not have the awareness or expertise needed to provide system security services. It is generally accepted that for distributed energy resources to provide system security services, this would occur through an aggregator who combines the capability of a number of distributed energy resources.

There are material transactional costs for aggregators to compile a portfolio of distributed energy resources to provide system services. Aggregators need relative certainty that they will be able to recover any investment made to be able to provide the services. To do so, they will need to gauge customer interest and contract with distributed energy resource owners, which may be both resource and time intensive. Additionally, they may incur costs to install communications systems and enable the required functionality in the distributed energy resources.

As a result, constructing a portfolio of distributed energy resources as a third party aggregator may be expensive and time consuming. The challenges of engaging and contracting with large numbers of participants are likely to be understood as knowledge is shared on the projects in the AEMO and ARENA demand response trial.[219] The trial comprises a number of pilot projects, including several to be undertaken by energy retailers, who will trial activities with residential and small business consumers, among others, to encourage demand response.

Need for 'firmness'

For an aggregator to offer system security services, the aggregator would have to bear the risk of the variability and lack of firmness of the contracted distributed energy resources.

System security services to date have generally been offered in large quantities. For example, FCAS offers currently need to be in MW increments. To offer these quantities of FCAS, an aggregator would need to account for the non-provision of services from contracted distributed energy resources. The aggregator may address this by complementing the distributed energy resources with some other firm generation, or discounting the offered quantity of service from distributed energy resources. Regardless, to be able to offer firm system security services, an aggregator is likely to have to bear material upfront costs and a degree of risk in providing the services to AEMO.

219 See: https://arena.gov.au/funding/programs/advancing-renewables-program/demand-response/

Value of providing system security services

System security services have historically been seen as low-value services because they are largely provided as a by-product of conventional, synchronous electricity generation. However, they are becoming increasingly valued as the generation mix changes. The changing value of these services may make it difficult for aggregators and distributed energy resource owners to make investment decisions.

It is likely that aggregators looking to use distributed energy resources to provide system services would also be considering other available value streams that can be captured by distributed energy resources, such as reducing wholesale costs for retailers or providing network support services. For an aggregator to justify the costs of contracting with a portfolio of distributed energy resources, it will likely need certainty that these costs can be recovered through payments for the services it has chosen to provide. A lack of a clear projection or forecast of value streams that can be captured through the aggregation of distributed energy resources, including in the provision of system security services, may therefore present an additional commercial challenge for potential aggregators.

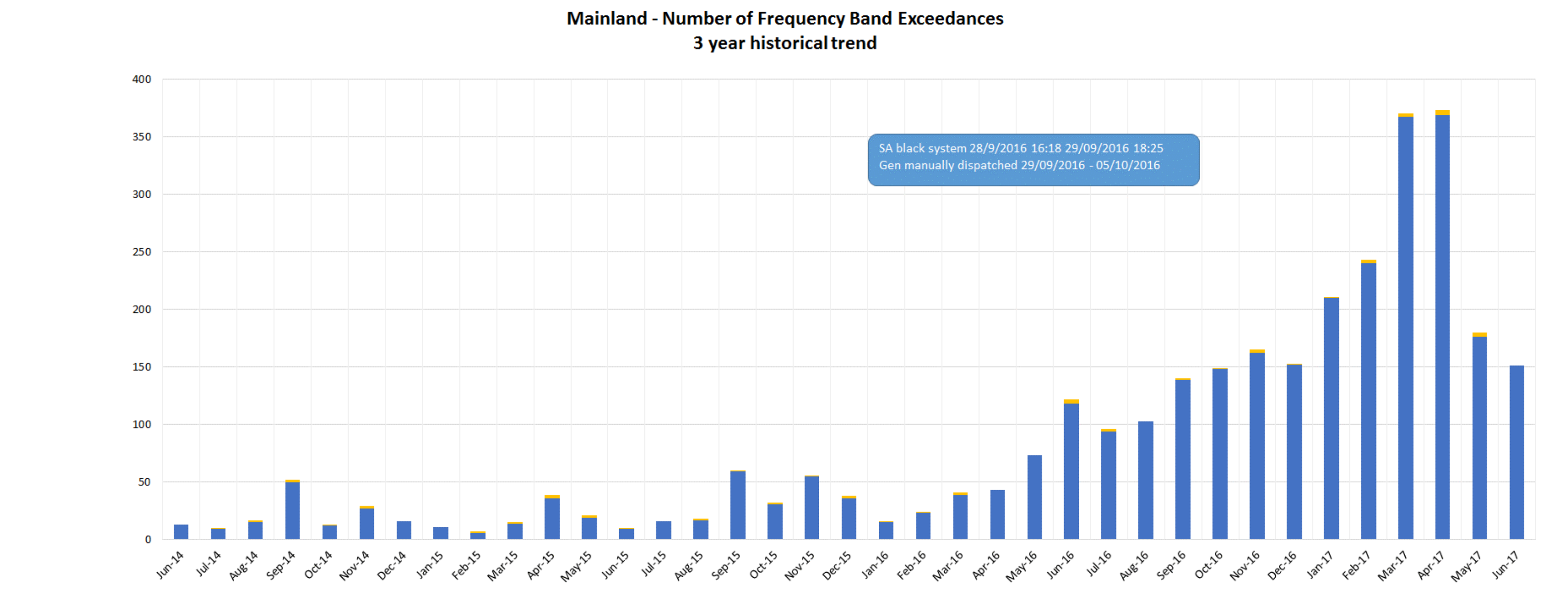
It is also possible that there are technical, regulatory or commercial barriers to the provision of the other value streams that result in there being a commercial barrier to aggregation of distributed energy resources for any purpose, not just for the provision of system services.

Question 25 Commercial challenges

Are there any other commercial challenges relevant to the provision of system services via distributed energy resources that are not discussed in this section?

A Frequency exceedances[220]

Figure A.1 Mainland - Number of frequency band exceedances: 2014 - 2017

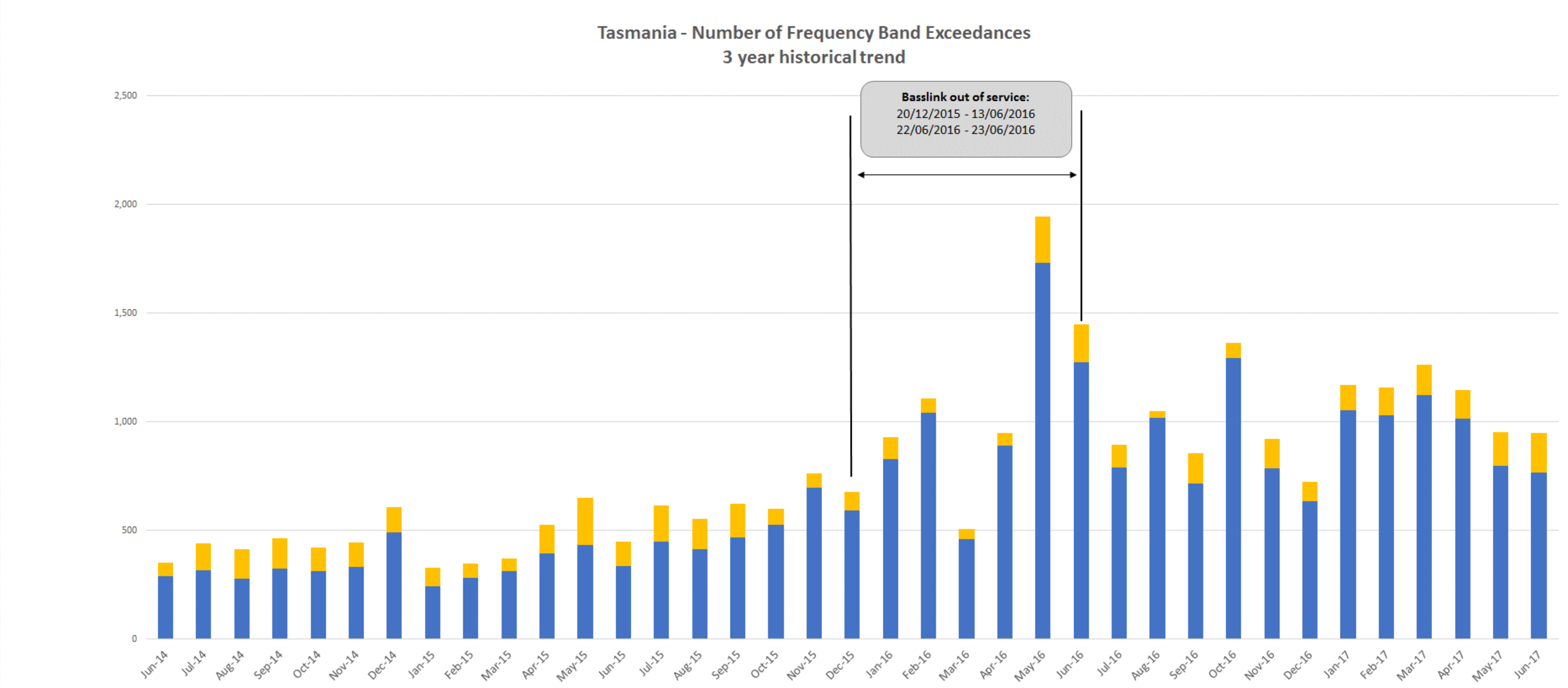


	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15
Outside 47 - 52 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 1 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 0.5 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 0.25 Hz band	0	1	2	2	1	2	0	0	1	1	3	2	1	0	1	1	1	1
Outside +/- 0.15 Hz band	13	9	15	50	12	27	16	11	6	14	36	19	9	16	17	59	31	55

	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
Outside 47 - 52 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 1 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 0.5 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 0.25 Hz band	2	1	1	2	0	0	4	2	0	1	1	3	1	1	3	3	4	4	0
Outside +/- 0.15 Hz band	36	15	23	39	43	73	118	94	103	139	148	162	152	210	240	367	369	176	151

220 AEMO 2017, Frequency monitoring – Three year historical trends, 9 August 2017.

Figure A.2 Tasmania - Number of frequency band exceedances: 2014 - 2017



	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
Outside 47 - 55 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 2 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 0.25 Hz band	62	121	138	139	109	113	115	87	69	59	134	215	113	167	136	155	71	65	85	103	65	46	57	216	174	103	30	142	68	136	92	117	126	138	135	156	181
Outside +/- 0.15 Hz band	292	319	278	325	313	331	491	243	281	314	394	434	336	450	416	470	528	698	591	828	1041	462	892	1730	1273	791	1020	715	1295	785	634	1054	1031	1124	1013	796	768