RULE

Australian Energy Market Commission

CONSULTATION PAPER

SYSTEM SERVICES RULE CHANGES

PROPONENTS

Hydro Tasmania, TransGrid
Infigen Energy, Delta Electricity

2 JULY 2020

INQUIRIES

Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

E aemc@aemc.gov.au
T (02) 8296 7800

Reference: ERC0290

CITATION

AEMC, System services rule changes, Consultation paper, 2 July 2020

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 energy sector is constantly changing — now more than ever. This rapid change is people-driven and market-driven as new technologies move us away from a system of large, remote, power stations towards smaller, distributed generators, impacting on both security and reliability:

- A **reliable power system** requires an adequate supply of capacity to meet demand and with a buffer available to respond to shocks, a reliable transmission and distribution network, and the system being in a secure operating state. Historically, reliability in the NEM has been high. However, as the supply-demand balance tightens there have been increasing concerns that reliability is becoming more challenging to manage — especially on very high temperature and high demand days.
- **Power system security** is the power system's capacity to continue operating within defined technical limits even if a major power system element, like a large generator or a major customer, disconnects from the system. The levels of system services like inertia, frequency control and system strength are deteriorating as the generation mix changes. These services, once provided as a 'by-product' of generating electricity from coal, gas and hydro generators are not being provided in the same way, or in the same amount any more.

This is reinforced by AEMO's Stage 1 *Renewable Integration Study*, which finds that, in the next five years the NEM power system will continue its significant transformation to world-leading levels of renewable generation, testing the boundaries of system security and current operational experience.

This requires a rethink of how we plan and develop market and regulatory frameworks in order to deliver a secure and reliable supply to customers.

In March 2019, the COAG Energy Council requested the Energy Security Board (ESB) to advise on a long-term, fit-for-purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources, including demand side response, storage and distributed energy resource participation. The AEMC is working closely with the ESB and the other market bodies on this work.

It is within that context, that the Australian Energy Market Commission (AEMC or Commission) has recently received six rule change requests that relate to the arrangements in the National Electricity Rules (NER) for the provision of services that are necessary for the secure and reliable operation of the power system. These are:

- **Hydro Tasmania — *Synchronous services markets*** — proposal to create a market for synchronous services such as inertia, voltage control and fault level/system strength.
- **Infigen Energy — *Operating reserve market*** — proposal to introduce a dynamic operating reserve market to operate alongside the existing NEM spot and FCAS markets, to help AEMO manage new and emerging operational challenges.

- **Infigen Energy — *Fast frequency response market ancillary service*** — proposal to introduce new ancillary service markets for fast frequency response (FFR) to efficiently manage power system risks associated with reduced system inertia.
- **TransGrid — *Efficient management of system strength on the power system*** — proposal to allow for TNSPs to be more proactive in the provision of system strength in the NEM. The request proposes to abolish the "do no harm" obligation and substantially amend the minimum system strength requirements.
- **Delta Electricity — *Capacity commitment mechanism for system security and reliability services*** — proposal to introduce an ex-ante, day ahead capacity commitment mechanism and payment to provide access to operational reserve and other required system security or reliability services.
- **Delta Electricity — *Introduction* of r*amping services*** — proposal to introduce 30-minute raise and lower "ramping" services using the existing framework for FCAS market design.

These rule change requests raise issues and propose solutions that relate to recent and ongoing work by the ESB and market bodies to reform the existing market and regulatory arrangements in the NEM to address emerging operational challenges and meet future power system needs.

Interaction with other work currently under way by the ESB and AEMO

The issues raised in the rule change requests complement and are interdependent with the issues being explored by the Energy Security Board (ESB) in its ongoing post-2025 market design program. In particular, the following ESB market design initiatives are relevant to these rule change requests:

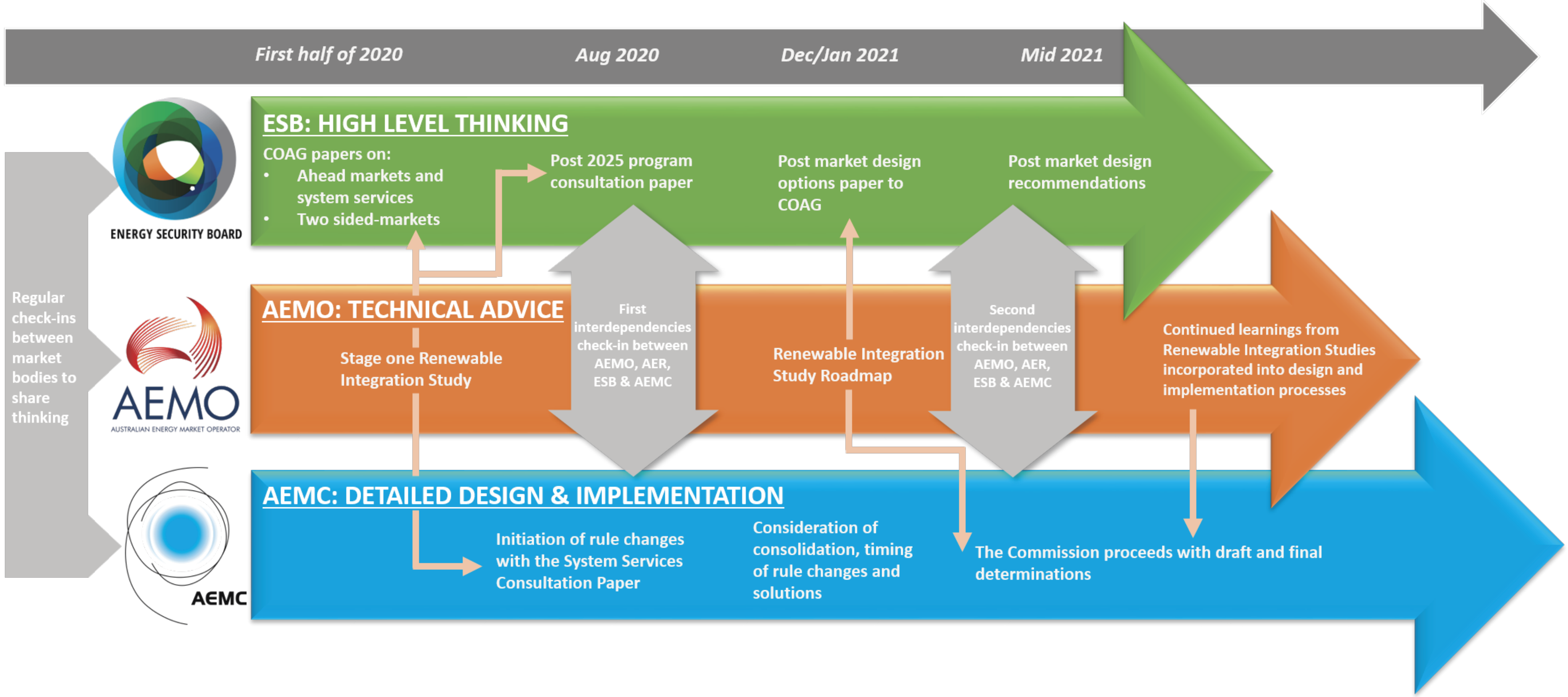
- **Resource adequacy mechanisms** — evaluation of potential options for additional resource adequacy mechanisms that could be implemented in the NEM post-2025. This includes considering the scenarios under which a new mechanisms may be needed to underpin new investment in the "right resources" to deliver reliable supply.
- **Ageing thermal generator strategy** — consideration of the need for additional market arrangements or regulatory approaches to deliver sufficient capacity and system services to replace large, ageing thermal generators as they exit the NEM.
- **Essential system services** — examination of efficient market mechanisms to value, procure and schedule essential system services.
- **Ahead markets** — assessment of mechanisms for improving visibility and effective scheduling of resources ahead of dispatch.

The AEMC is working closely with the ESB and the other market bodies, particular AEMO on these rule change requests, given that these rule changes dovetail with this other work. The rule change requests complement and are interdependent with the work of the ESB in its 2025 project. These rule change requests provide us with an opportunity to complement the thinking and assessment done in the ESB work program. It allows us to address the issues in a cohesive way, as well as addressing system security issues that are more urgent in nature.

In addition, the assessment of the rule change requests discussed in this consultation paper will need to be informed by an understanding of the physical needs of the power system. Recent and ongoing work by AEMO will be key technical inputs in order to understand these power system requirements. One AEMO project that is particularly relevant to the system services rule change requests is AEMO's 2020 *Renewable integration study*.

Figure 1 demonstrates how the work programs fit together.

Figure 1: AEMC consultation timeline including relevant ESB post-2025 milestones



Interaction with other AEMC work under way

There are also two additional projects currently being undertaken by the AEMC that directly relate to the six rule change requests that are the subject of this consultation paper. These projects are:

- The AEMC's *Investigation into system strength frameworks in the NEM* (System strength investigation).[1]
- The AEMC's assessment of AEMO's rule change request, *Primary frequency response incentive arrangements.*[2]

Approach

The AEMC is commencing consultation on the six rule change requests at the same time via this single consultation paper. This is because each of the rule change requests relate to the provision of one or more system services to keep the power system secure and reliable.

The six rule change requests discussed in this paper, along with the *Primary frequency control incentive arrangements* rule change request already under way, each propose specific solutions to making sure we have sufficient system services (both for reliability and security) that would operate predominantly within a specific time frame.

The AEMC has used the proponent's proposed solutions to group the rule change requests into three time frame-based "work streams" to allow common issues to be considered and consultation to be streamlined. These are described as the investment, commitment and dispatch time frames.

Establishing work streams based on the specific solutions proposed by the proponents is a conceptual approach to grouping the rule change requests and provides a useful starting point for consultation. However, it does not necessarily define the outcome of any rule change that might be made in response to the rule change requests. How each service identified in each rule change request could be planned, procured, priced and paid for will be considered across *all* time frames, not just the predominant one identified in the solution proposed in each rule request. Any new frameworks developed in response to the rule change requests will be focused on delivering the most efficient outcomes for consumers, having regard to outcomes across all time frames.

1 https://www.aemc.gov.au/market-reviews-advice/investigation-intervention-mechanisms-and-system-strength-nem

2 *This rule change request has previously been referred to by the Commission as the Removal of disincentives to the provision of primary frequency response*

Figure 2: Time frames for the provision of system services

Work stream	Rule change request	Issues to be considered in investment timeframe	Issues to be considered in commitment timeframe	Issues to be considered in dispatch timeframe
Dispatch	*AEMO – Primary frequency response incentives (ERC0263)*	Specification of the service Specification of any mandatory obligations	Commitment of synchronous generation determines quantity of PFR	Could potentially be co-optimised with energy and FCAS at dispatch (if included in the service)
	Infigen Energy – Fast frequency response market (ERC0296)	Specification of the service Long-term procurement for non-credible contingencies	Providers of FFR are unlikely to require commitment	Co-optimised with energy and FCAS at dispatch
Commitment	*Delta Electricity – Capacity commitment mechanism for system security and reliability services (ERC0307)*	Market participant planning	Some Service providers require a commitment decision	Payment may depend on 5-minute interval prices
	Delta Electricity – Introduction of ramping services (ERC0397)	Market participant planning Long-term procurement (e.g. RERT)	Some Service providers require a commitment decision	Co-optimised with energy and FCAS at dispatch
	Infigen Energy - Operating reserve market (ERC0295)	Market participant planning Long-term procurement (e.g. RERT)	Some Service providers require a commitment decision	Co-optimised with energy and FCAS at dispatch
Investment	*TransGrid – Efficient management of system strength on the power system (ERC0300)*	Planning, building or long-term contracting with synchronous services	Relying on directions/constraints for any sudden service shortfall	Scheduled/operated by AEMO and TNSPs
	Hydro Tasmania – Synchronous services markets (ERC0290)	Determination of impacts on security constraints	Determination of impacts on security constraints	Co-optimised with energy and FCAS at dispatch
	AEMC system strength investigation (EPR0076)	Obligations on AEMO and NSPs for system strength planning	Consideration of operation measures and directions to provide residual system strength requirements	Consideration of how system strength is accounted for in pre-dispatch
Key:	*Proponent's solution functions predominantly over the dispatch timeframe*	*Proponent's solution functions predominantly over the commitment timeframe*	*Proponent's solution functions predominantly over the Investment timeframe*	*Proponent's solution functions over no identifiable timeframe. This rule change request will initially be considered as a part of the investment work stream.*

Source: AEMC

Time frames for consultation

This consultation paper has been published to facilitate consultation on the six rule change requests from Delta Electricity, Hydro Tasmania, Infigen and TransGrid.

Submissions in response to these rule change requests should be provided to the AEMC by **13 August 2020**.

Following receipt of stakeholder submissions, the AEMC will update stakeholders on the next steps for each of the work streams and the related rule change requests, including timing. This will include consideration of how each rule change request can dovetail in with other work under way.

CONTENTS

APPENDICES

TABLES

FIGURES

1 INTRODUCTION

The Australian Energy Market Commission (AEMC or Commission) has recently received six rule change requests that seek to amend the National Electricity Rules (NER) to better allow for the provision of services that are essential for maintaining the power system in a secure operating state and delivering a reliable supply to electricity consumers.

The assessment of these rule change requests relates to one of the AEMC's five priority areas, namely that of 'power system security', which is focused on developing market and regulatory frameworks which allow continued take-up of new generating technologies while keeping the lights on at the least cost to consumers.

The AEMC's work on these rule changes is being progressed in close coordination with the Energy Security Board (ESB). The ESB is progressing a number of complementary market design initiatives in its 2025 work, which are related to the development of new system services.

This consultation paper has been prepared to facilitate public consultation on the six system services rule change requests and to guide stakeholder submissions in relation to the issues raised and the solutions proposed by the rule change proponents in the respective rule change requests.

1.1 Purpose of this consultation paper

The consultation paper has been prepared to facilitate public consultation on the rule change requests and to seek stakeholder submissions. This paper:

- explains the conceptual approach to considering reforms to the market and regulatory arrangements for power system security and reliability
- describes how this work program will be coordinated with other related projects by the ESB, AEMC and the other market bodies
- outlines the assessment framework and priorities
- summarises the issues raised and solutions proposed in the rule change requests
- identifies a number of issues and questions to facilitate the consultation on these rule change requests
- describes the process for stakeholders to provide submissions on the rule change requests.

The AEMC welcomes submissions in response to this consultation paper on one or more of the rule change requests.

The AEMC also welcomes interested stakeholders to contact us if they would like to meet with us to discuss one or more of the rule change requests or any related issues.

Enquiries in relation to the system services rule change requests should be directed to the relevant project leader as per the table below:

Table 1.1: Contact information

RULE CHANGE REQUEST	AEMC PROJECT LEAD AND CONTACT DETAILS
Hydro Tasmania — Synchronous service markets (ERC0290)	James Hyatt James.Hyatt@aemc.gov.au ph. 02 8296 1628
TransGrid — Efficient management of system strength on the power system (ERC0300)	
Infigen Energy — Fast frequency response market ancillary service (ERC0296)	Ben Hiron Ben.Hiron@aemc.gov.au ph. 02 8296 7855
Infigen Energy — Operating reserve market (ERC0295)	Jessie Foran Jessie.Foran@aemc.gov.au ph. 02 8294 7864
Delta Electricity — Capacity commitment mechanism for system security and reliability services (ERC0306)	
Delta Electricity — Introduction of ramping services (ERC0307)	

1.2 Energy Security board post-2025 market design

The issues raised in these rule change requests complement and are interdependent with issues explored by the ESB in its post-2025 market design work.

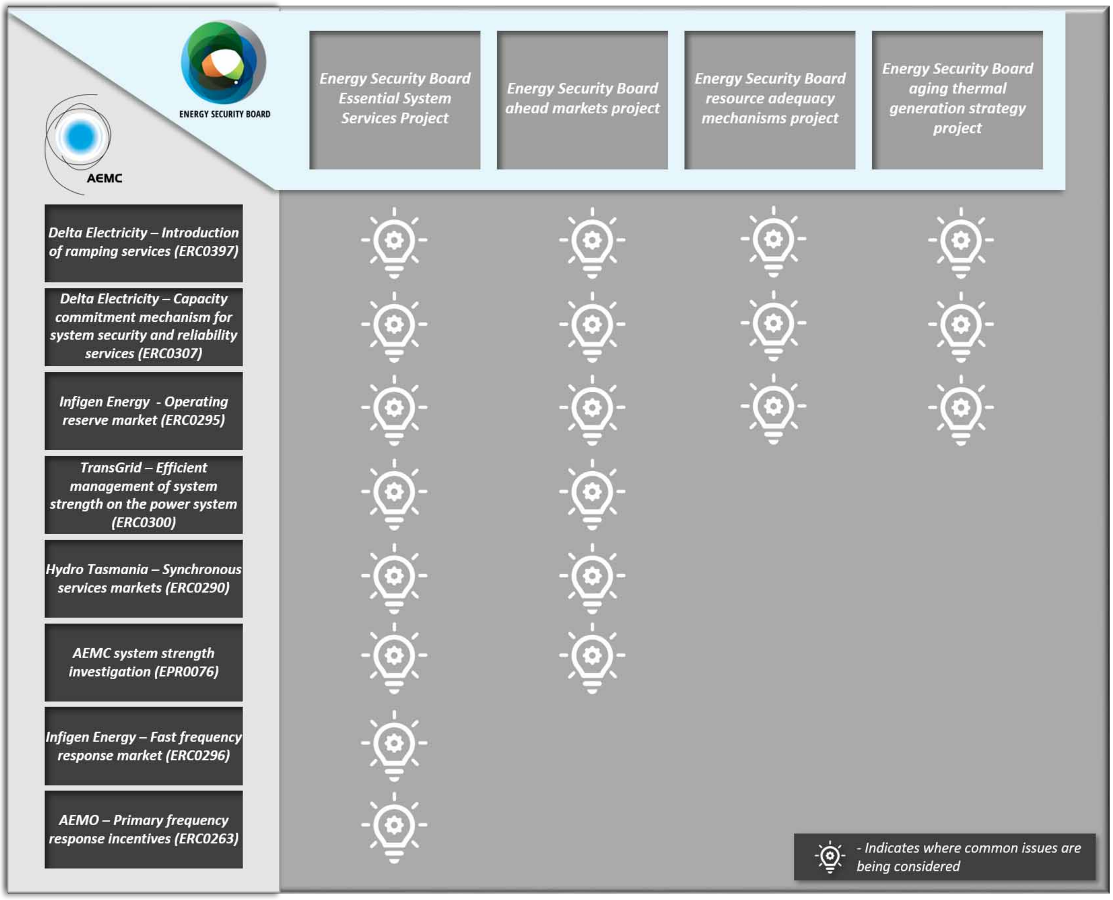
The ESB is developing advice on alternative, long-term, fit-for-purpose market design options that could apply from the mid-2020s, to be provided as recommendations to COAG Energy Council by the end of 2020. Multiple forward-looking reform initiatives are contained within the post-2025 work, with each initiative led by the ESB or one of the respective market bodies. These programs include exploration of the following Market development initiatives (MDIs):

- **Resource adequacy mechanisms** — evaluate potential options for additional resource adequacy mechanisms that could be implemented in the NEM post-2025, including considering the scenarios under which a new mechanism may be needed to underpin new investment in the "right resources" and deliver reliable supply.
- **Ageing thermal generator strategy** — consider need for additional market arrangements or regulatory approaches for ensuring sufficient capacity and system services are available to replace large, ageing thermal generators as they exit the NEM.
- **Essential system services** — develop a framework to identify efficient market mechanisms to value, procure and schedule essential system services and a general regulatory framework that is flexible and can adapt with minimal reform processes.
- **Ahead markets** — assess mechanisms for improving visibility and effective scheduling of resources ahead of dispatch.

- **Two-sided markets** — create a market where both supply and demand sides are obligated to bid into the spot market.
- **Distributed energy resources (DER) markets** — considering options to better integrate DER in the NEM.
- **Coordination of generation and transmission investment (CoGaTI)** — process to introduce dynamic locational pricing and financial transmission rights in the NEM.

Of the ESB's seven market development initiatives there are four that specifically relate to the package of system services rule change requests discussed in this consultation paper. Figure 1.1 below highlights where the ESB's market development initiatives are exploring issues that relate to one or more of the system services rule change requests.

Figure 1.1: Interactions between ESB post-2025 MDIs and AEMC system services projects



Source: AEMC

The purpose of the 2025 project is to consider what market design might be needed to meet consumer needs and ensure affordability, reliability and security in the medium to long term. The 2025 project is examining a full range of resource adequacy mechanisms, and market and non-market means to provide system services. This includes various forms of operating reserves, and other resource adequacy mechanisms, as well as mechanisms to more efficiently procure, commit and dispatch a range of system services, some of which overlap with the rule change requests.

The AEMC is working closely with the ESB and the other market bodies, particularly AEMO (see Figure 1.2) on these rule change requests, given that these rule changes dovetail with this other work. The rule change requests complement and are interdependent with the work of the ESB in its 2025 project. These rule changes provide us with an opportunity to complement some of the thinking and assessment done in the ESB work program, as well as technical input from AEMO through its *Renewable integration study*. It allows us to address the issues in a cohesive way, as well as addressing system security issues that are more urgent in nature.

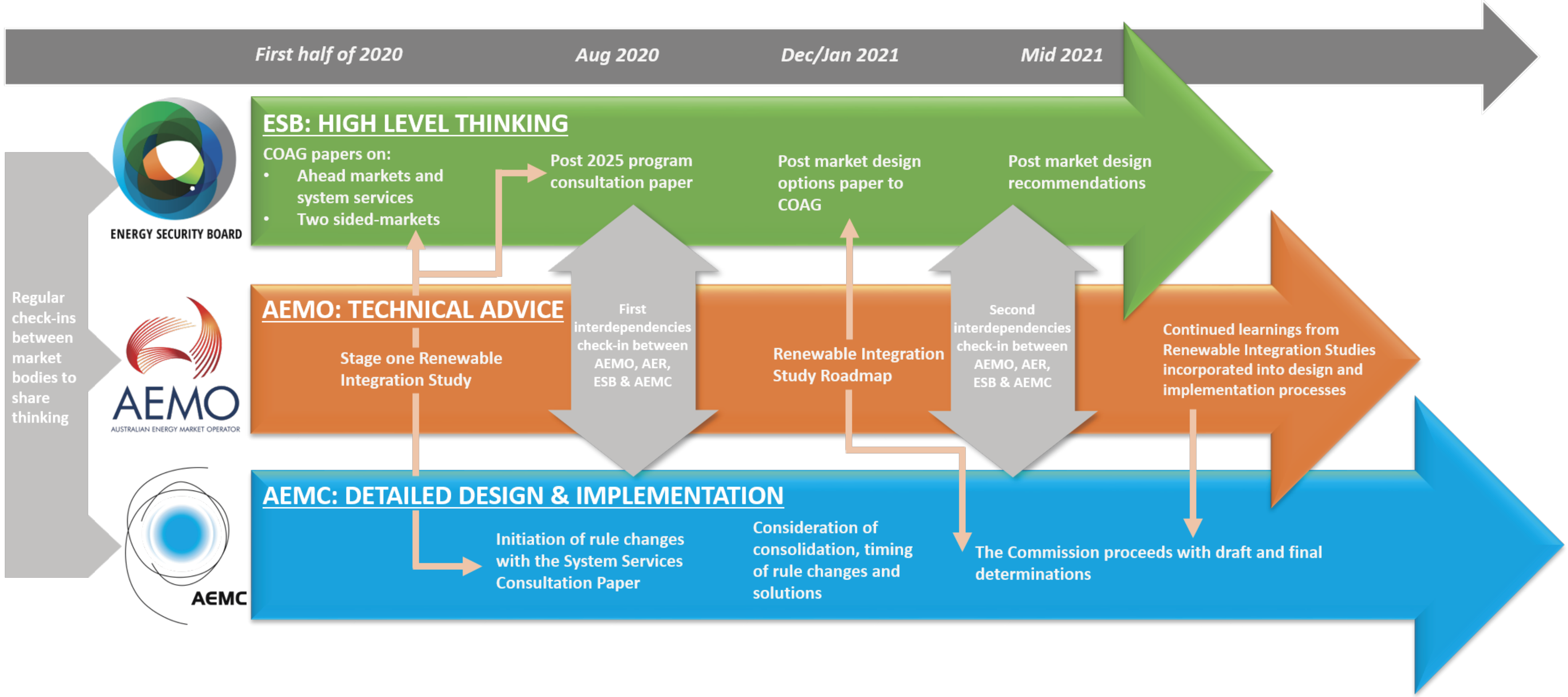
While working with the ESB's 2025 project, the AEMC will be progressing rule changes that address issues in the market that meet the long-term of interests of consumers, considering relevant longer-term options being developed in the ESB's 2025 project.

To ensure the various work streams are fully coordinated, the ESB will review, at its monthly Board meeting the inter-dependencies between the AEMC rule changes and the 2025 project, prior to critical decision points for each process.

Responses to the consultation questions in this paper will be used by the 2025 project to inform its analysis. In progressing these rule changes, the AEMC will consider responses to the 2025 project's August consultation paper where relevant to its assessment.

Figure 1.2 demonstrates how the work programs fit together.

Figure 1.2: AEMC consultation timeline including relevant ESB post-2025 milestones



1.3 AEMO system services work

The AEMC's assessment of the rule change requests discussed in this consultation paper will be informed by an understanding of the physical needs of the power system. Two areas of AEMO's work that will be particularly key inputs into the assessment of the system services rule change requests are:

- the 2018 and 2020 *Integrated system plans*
- the 2020 *Renewable integration study*

1.3.1 The Integrated system plan

In July 2018, AEMO published its inaugural Integrated system plan (ISP).[3] AEMO updates the ISP every two years with the next version due for final publication in by 30 June 2020.[4]

In the ISP, AEMO forecasts the overall transmission system requirements for the NEM over the next 20 years. It identifies a potential plan of the transmission investments that AEMO believes will be necessary to support the long term interests of consumers for safe, secure, reliable electricity, at the least cost, across a range of plausible futures.

The key findings of the 2018 ISP included:

- grid demand is expected to flatten due to the growth of rooftop photovoltaic (PV) and increasing use of local storage,
- over the next 20 years, a percentage of the NEM’s existing coal resources will be approaching the end of their technical lives,
- changing investment profile and capabilities of various supply resources,
- costs of new renewable plants are falling and advancements are expected in the capability and availability of storage technologies.

AEMO's Draft 2020 ISP sets out an actionable roadmap for eastern Australia’s power system to maximise market benefits through a transition period of complexity and potential uncertainty. The key elements of the 2020 ISP are:[5]

- provides a whole-of-system plan to maximise net market benefits and deliver low-cost, secure and reliable energy through a complex range of plausible energy futures,
- is based on cost-benefit analysis and least-regret scenario modelling, covering five scenarios and six sensitivities,

3 AEMO, Integrated system plan - for the National electricity market, July 2018.

4 National Electricity Amendment (Integrated System Planning) Rule 2020, clause 5.22.1. This rule was made by the SA Minister on 2 April 2020 and will commence on 1 July 2020.

5 AEMO, Draft 2020 Integrated system plan, 12 December 2019, p.7.

- has identified the investments needed for Australia's future energy system: in distributed energy resources[6], variable renewable energy (VRE)[7], supporting dispatchable resources and power system services, and the NEM transmission grid,
- sets out the optimal development path for Australians to enjoy an affordable, secure and reliable energy future, the signposts at which that path may need to change course, and the options we may then have. This includes actionable ISP projects and other initiatives that are needed immediately, shortly or in the future.

The ISP will provide valuable input in developing system services frameworks that effectively support the power system now and in the future.

1.3.2 The Renewable integration study

On 30 April 2020, AEMO published its stage 1 report for the *Renewable integration study* (RIS).[8]The RIS investigates and describes the requirements for operating the national electricity system securely through to 2025. It seeks to quantify the technical renewable penetration limits of the power system for a projected generation mix and network configuration in 2025.

The RIS stage 1 report builds on previous work by AEMO including the power system projections developed through the ISP, the power system requirements paper and AEMO's review of international approaches to operating power systems with high penetrations of wind and solar generation.[9] The RIS outlines five focus areas to keep the power system secure and identifies challenges associated with operating the NEM power system with higher levels of instantaneous wind and solar generation.

The RIS stage 1 paper includes a list of actions and recommendations that are intended to address the key power system challenges. The findings and recommendations from AEMO's RIS are a valuable input to the AEMC's consideration and assessment of the system services rule change requests.

Appendix B provides more information about how the focus areas and challenges identified by AEMO in the RIS align with the package of system services rule change requests initiated with the publication of this paper.

QUESTION 1: CURRENT ESB & AEMO WORK RELATING TO THE RULE CHANGE REQUESTS

1. What are stakeholders' views on how the rule change processes should be integrated with ESB and AEMO work programs?

6 Including rooftop PV, batteries, and other resources at the customer level

7 Including solar, wind, battery and other energy resources.at the utility level

8 AEMO, *Renewable integration study*: Stage 1 report, April 2020.

9 AEMO, Maintaining Power System Security with high penetrations of wind and solar generation — International insights for Australia, October 2019.

2. Are there any additional processes that should be closely considered by the Commission when progressing these rule change requests?

1.4 Overview of the rule change requests

The AEMC has recently received six rule change requests that relate to the arrangements for the provision of essential system services in the national electricity market (NEM). These rule change requests and the respective proponents, are:

- Hydro Tasmania — *Synchronous services markets* (ERC0290)
- Infigen Energy — *Operating reserves market* (ERC0295)
- Infigen Energy — *Fast frequency response market ancillary service* (ERC0296)
- TransGrid — *Efficient management of system strength on the power system* (ERC0300)
- Delta Electricity — *Capacity commitment mechanism for system security and reliability services* (ERC0306)
- Delta Electricity — *Introduction of ramping services* (ERC0307)

Copies of the rule change requests are available on the AEMC website.

This section provides a brief overview of each rule change request.

1.4.1 Hydro Tasmania — *Synchronous services markets* (ERC0290)

On 19 November 2019, the AEMC received a rule change request from Hydro Tasmania to amend the National Electricity Rules (NER) to create a market for synchronous services such as inertia, voltage control and fault level/system strength.

The proposal is intended to incorporate system service requirements into the formulation of constraints that are applied to the NEM dispatch engine (NEMDE). These reformulated constraints would allow the dispatch engine to find the lowest overall cost combination of synchronous and non-synchronous generation, while also delivering the necessary levels of system services. The cost of providing these services would be recovered from consumers through an uplift to the wholesale energy price.

The rule change request does not include proposed rule drafting.

1.4.2 Infigen Energy — *Operating reserve market* (ERC0295)

On 19 March 2020, the AEMC received a rule change request from Infigen Energy to amend the NER to introduce a dynamic operating reserve market to operate alongside the existing NEM spot and FCAS markets, to help AEMO manage new and emerging operational challenges. The proposed operating reserve market would procure reserves 30 minutes ahead of time (with a 15-minute call time) to align with requirement to return the system to a secure operating state within 30 minutes.

The rule change request does not include proposed rule drafting.

1.4.3 Infigen Energy — *Fast frequency response market ancillary service* (ERC0296)

On 19 March 2020, the AEMC received a rule change request from Infigen Energy to amend the NER to introduce new ancillary service markets for fast frequency response (FFR) to efficiently manage power system risks associated with reduced system inertia. The proposed markets for raise and lower FFR would operate similar to the existing market arrangements for FCAS.

The rule change request does not include proposed rule drafting.

1.4.4 TransGrid — *Efficient management of system strength on the power system* (ERC0300)

On 27 April 2020, the AEMC received a rule change request from TransGrid to amend the NER to allow for TNSPs to be more proactive in the provision of system strength in the NEM. The request proposes to abolish the "do no harm" obligation and substantially amend the minimum system strength requirements. TransGrid argue this is necessary to address issues with the existing system strength framework, that have arisen since it was put in place in 2017.

The rule change request does not include proposed rule drafting.

1.4.5 Delta Electricity — *Capacity commitment mechanism for system security and reliability services* (ERC0306)

On 4 June 2020 the AEMC received a rule change request from Delta Electricity to amend the NER to introduce an ex-ante, day ahead capacity commitment mechanism and payment to provide access to operational reserve and any other system security or reliability services that AEMO may require to meet its security and reliability objectives.

The rule change request does not include proposed rule drafting.

1.4.6 Delta Electricity — *Introduction of ramping services* (ERC0307)

On 4 June 2020 the AEMC received a rule change request from Delta Electricity to amend the NER to introduce 30-minute raise and lower "ramping" FCAS services using the existing framework for FCAS market design. Delta suggests these ramping services would address the price volatility that exists when dispatchable generators ramp through their energy bid stacks in response to predictable, daily, high rates of change from solar ramping up and down.

The rule change request does not include proposed rule drafting.

1.5 Process for consultation on the rule change requests

The Commission is commencing consultation on the six rule change requests at the same time via this single consultation paper. This is because each of the rule change requests relate to the provision of one or more system services to keep the power system secure and reliable. The AEMC wishes to initiate the rule change requests together in order to allow stakeholders to comment on and consider the interactions between issues raised in relation to the different system services and the different solutions proposed.

The Commission is also mindful of the challenge for stakeholders keeping track of the large volume of regulatory reforms under way. The coordinated approach to consultation on the system services rule change requests is intended to help reduce this overall burden on stakeholders.

However, this does not mean that the rule change requests will continue to be considered together going forward. Accordingly, the Commission has not, at this stage, consolidated the rule change requests. Assessing each rule change request separately allows for assessment of the issues raised and potential solutions on a timeline that reflects the priority for the NEM, including addressing the issues that are more urgent in nature.

The following section provides an overview of two ongoing AEMC projects that directly relates to the assessment of these rule change requests.

1.5.1 Related AEMC projects

As part of the AEMC's ongoing work related to power system security, there are two active projects that directly relate to the six rule change requests that are the subject of this consultation paper. These projects are:

- The AEMC's *Investigation into system strength frameworks in the NEM* [10]
- The AEMC's assessment of AEMO's rule change request, *Primary frequency response incentive arrangements*.[11]

These active projects are described below and are also being undertaken in coordination with the ESB and AEMO work discussed above.

Investigation into System strength frameworks in the NEM

The AEMC is currently progressing an investigation into the effectiveness of the regulatory frameworks for the provision of system strength.

The Commission established the current system strength frameworks in 2017, to address immediate system strength issues. These frameworks have largely been successful in keeping the system secure. However, the pace of the transition in the power system means the time has now come to adjust and expand the system strength frameworks, given the rapid growth in the connection of large numbers of new non-synchronous generation.

The Commission initiated its investigation into system strength frameworks (system strength investigation) to examine [12] how to evolve the system strength frameworks to manage this transition.

The AEMC published a discussion paper in March 2020 in relation to this review.[13] This paper set out the key issues with the current frameworks, the attributes of system strength as well as the Commission's approach and high-level models of evolving the frameworks.

10 https://www.aemc.gov.au/market-reviews-advice/investigation-intervention-mechanisms-and-system-strength-nem

11 Note — This rule change request has previously been referred to by the Commission as the *Removal of disincentives to primary frequency response.*

12 https://www.aemc.gov.au/market-reviews-advice/investigation-intervention-mechanisms-and-system-strength-nem

13 AEMC, *Investigation into System strength frameworks in the NEM: Discussion paper,* March 2020.

The Commission is now working towards publishing a final report in September-October this year. It will set out the high-level design of how the system strength (and associated inertia) frameworks can be evolved. The details of these reforms will then be progressed through current rule change requests, including TransGrid's *Efficient management of system strength on the power system* rule change request, and Hydro Tasmania's *Synchronous services markets* rule change request (which are two of the six rule change requests discussed in this consultation paper).

Primary frequency response incentive arrangements

On 3 July 2019, AEMO submitted a rule change request relating to the observed degradation of frequency performance in the national electricity system during normal operation. AEMO identified a series of perceived disincentives in the NER to generators voluntarily operating their plant in frequency response mode, leading to a reduction in the amount of plant in the NEM that provide PFR.[14]

On 19 September 2019, the AEMC published a consultation paper and initiated this rule change request, along with two other rule change requests related to primary frequency response, one submitted by AEMO and one by Dr. Sokolowski. These other rule change requests were consolidated under the Mandatory primary frequency response rule change project, and a final determination and rule published on 26 March 2020, which introduced temporary arrangements for the provision of mandatory primary frequency response.[15]

On 19 December 2019, the Commission extended the period for making the draft determination for AEMO's remaining PFR rule change (ERC0263) to 24 September 2020. This rule change request was originally named, *Removal of disincentives to the provision primary frequency response.* To more accurately reflect the scope and objectives for this rule change request in the context of the other rule changes discussed in this consultation paper the Commission has renamed this rule change project: *Primary frequency response incentive arrangements*.

The remaining objectives for this rule change request are to investigate the appropriateness of the existing incentives for the provision of PFR during normal operation and amend these arrangements as required to meet the future needs of the power system.[16]

The Commission intends to work with stakeholders and AEMO on the detailed directions for this rule change request which will include consideration of:[17]

- the arrangements for allocation of costs associated with regulation services — 'causer-pays'
- the potential development of additional complementary measures to effectively remunerate providers of primary frequency response

14 AEMO, *Removal of disincentives to the provision primary frequency response under normal operating conditions* rule change request, 1 July 2019, pp. 14-16.

15 AEMC, *Mandatory primary frequency response — final determination*, 26 March 2020.

16 AEMC, *Mandatory primary frequency response final determination,* 26 March 2020, p.25.

17 AEMC, *Mandatory primary frequency response final determination,* 26 March 2020, p.41.

- interaction with the arrangements in the Mandatory primary frequency response final rule including the sunset arrangements.

1.6 Timetable for the consultation process

The Commission invites stakeholders to make submissions for a period of six weeks, with submission due **13 August 2020**.

Following receipt of stakeholder submissions, the Commission will work with the ESB, AEMO, AER and stakeholders on the direction for each of the work streams and the related rule change requests. This will follow the August 2020 consultation paper for the ESB's 2025 work and so will allow the processes to be complementary.

Given the complexity and broad scope of issues covered by the rule change requests, affecting many areas of the NER, as well as the interactions with ESB work programs, the standard rule making time frames for some of the requests may need to be extended. Stakeholder views received in response to this paper will inform the timeline and process, as well as the ESB's work. The Commission will notify stakeholders of the process and time frames that will be adopted for the remainder of the assessment of each rule change request in Q3 2020.

The Commission will provide updates to the expected timetable for the rule change requests via the respective project pages on the AEMC website.

QUESTION 2: **TIMETABLE FOR THE CONSULTATION PROCESS**

1. Do stakeholders have any comments on the proposed timetable for the system services rule changes?

2 SYSTEM SERVICES OVERVIEW

This chapter provides a brief overview of what reliability and security ("system") services are in the NEM and the drivers of their change over time. The purpose of this chapter is to provide background to the six rule change requests discussed later in this paper.

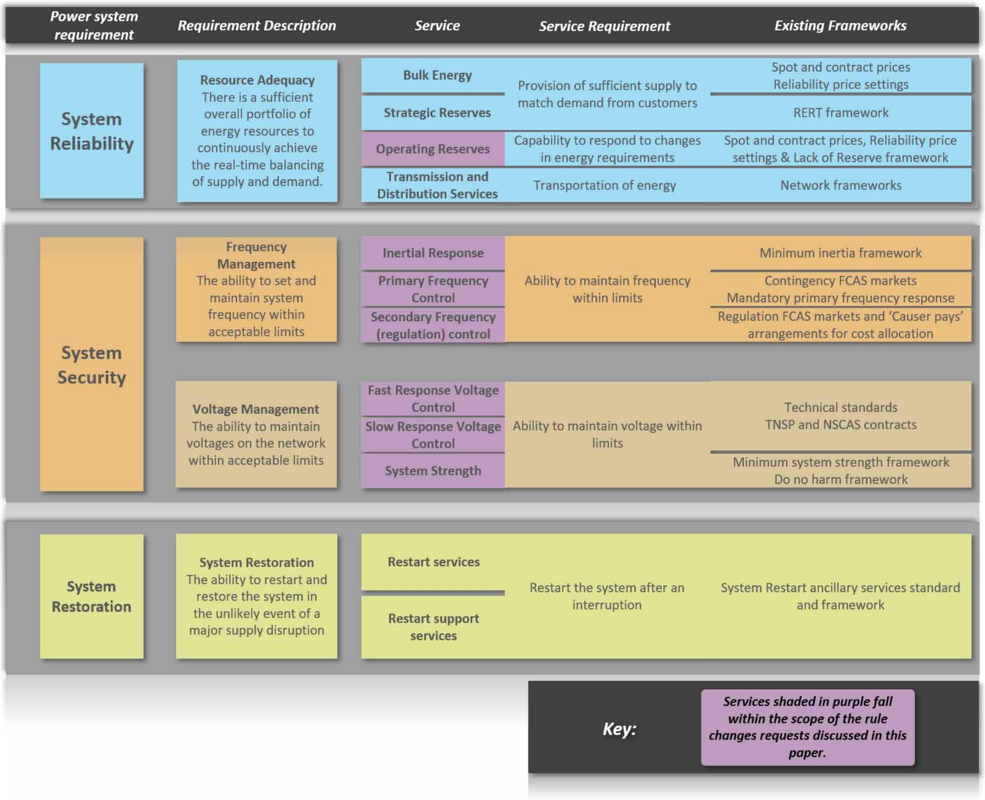
2.1 What are system services and their existing arrangements?

In order to maintain a secure and reliable power system, a number of fundamental power system requirements must be satisfied at all times, through the provision of several physical services, relating to both security and reliability. These are commonly called "system services", and are delivered across both operational and investment time-scales. Power system elements will not operate effectively without adequate levels of these services, for example disconnecting, islanding, or causing faults or black outs.

AEMO sets out these system services in its *Power System Requirements* document. Figure 2.1 below summarises these system services highlighting (in purple) the services that are the subject of the rule change requests covered in this paper.[18]

18 AEMO, Power System Requirements, p. 9, March 2018.

Figure 2.1: System services and their existing arrangements



Source: AEMC — Service breakdown based on AEMO's *Power system requirements,* March 2018.
Note: Services coloured purple are within the scope of the rule changes requests discussed in this paper.
Note: For more information on these existing system strength frameworks see AEMC's *System strength investigation: Discussion paper*, March 2020, appendix A & B. For more information on the existing frameworks for frequency control refer to the AEMC's *Frequency control frameworks review — Issues paper*, 7 November 2017, Chapter 2.

2.2 Drivers of system services change over time

This section provides an overview of the principal drivers for the changes in the system services set out above.

Recent increases in the demand for **reliability services** and increasing use of intervention mechanisms in order to promote reliability in the system, has increased concern regarding the reliability of the NEM in the last few years.

In addition, planning and operating the power system is far more challenging than ever before. Historically power system planning was based on relatively few, well understood risk factors due to uniform generation technologies connecting to the grid. The increase in the diversity of generation technologies that are now being connected to the grid, and their geographic decentralisation, brings additional, complex and interrelated risk factors to the reliability of supply. Also, many of these risk factors are difficult to forecast. Compounding these risks are increasingly frequent extreme weather conditions that impact on both supply and demand. All of these have had an impact on reliability services.

In relation to **system security services,** these are no longer provided as a natural "by-product" of the production of energy. We therefore need to consider how these services can be actively provided, to keep the system secure.

Traditionally these system services were provided by synchronous generators as a matter of course, as a by-product when generating energy. However, the NEM is transitioning to a power system with a higher number of non-synchronous generators, and fewer synchronous generators.[19] These non-synchronous generators do not produce all of these system services, as a by-product of energy generation.

Similar to the above, there have been impacts on how **system restoration services** can be provided driven given technology advances and the changing generation mix.

Projections outlined in AEMO's RIS stage 1 report indicate how non-synchronous wind and solar generation capacity in the NEM will increase from 17 gigawatts (GW) in 2019 to 27 GW in 2025.[20] Over the longer time periods considered in the ISP, this number grows to at least 30-40GW of non-synchronous generation by 2040, coupled with the expected exit of 15 GW of synchronous generation.[21] In the stage 1 RIS report, AEMO notes that:[22]

> Given the pace and complexity of change in the NEM, the RIS highlights the need for flexible market and regulatory frameworks that can adapt swiftly and effectively as our understanding of the changing power system evolves.

This power system transition is changing the way that these system services are being provided and therefore the way the regulatory frameworks operate.

For example, a reduction in the availability of system services has physical implications for the power system. This in turn impacts on AEMO's ability to effectively manage power system security. For example, the ability to suppress rapid frequency deviations and control power system frequency becomes more difficult as levels of inertia decline. Similarly, a reduction in system strength will negatively impact on the operation of network protection systems as well as the stability of non-synchronous generators.

2.3 Recent work and regulatory reforms relating to system services

The AEMC, working with AEMO, has completed multiple projects and regulatory reforms in recent years that relate to the provision of services needed to underpin a secure and reliable

19 Synchronous generators (which historically have included coal, gas and hydro generators) are electro-mechanically coupled to the power system, and inherently provide system services like inertia, reactive power support and system strength. Non-synchronous generators (which typically include solar PV and wind generators), are connected to the power system through power electronics. This means that while these non-synchronous generators can provide some services that were provided by synchronous generators, they do not do so automatically, as a by-product of their energy generation.

20 AEMO, Renewable Integration Study: Stage 1 report, April 2020, p.18. Stage 1 of the RIS is primarily based on analysis to the year 2025 from the project generation build under the central scenario in the Draft 2020 ISP.

21 AEMO, *Draft 2020 Integrated system plan*, 2019, pp. 34-37.

22 AEMO, Renewable Integration Study: Stage 1 report, April 2020, p. 14.

power system as technologies and business models change. These regulatory reforms are summarised in appendix a.

The rule change requests discussed in this consultation paper will be considered in the context of these recent projects.

3 APPROACH

This chapter sets out the AEMC's approach to progressing the six rule change requests discussed in this consultation paper alongside the existing rule change request on *PFR incentive arrangements* and the *Investigation into system strength frameworks*.

It outlines how the different services outlined in the previous chapter can be provided across a range of time frames, and the proposed approach to characterising the rule change requests through three broad time frame-based work streams.

3.1 Provision of system services across different time frames

A secure and reliable power system requires supply and demand for electricity to be balanced at all times. A range of system services are also required to support the proper technical operation of the power system. The supply of bulk energy and of system services must therefore be managed over seconds, minutes, hours, days, months and years.

While the balancing of bulk energy is generally managed in real time,[23] a range of regulatory frameworks and mechanisms, operating over a range of time frames, can be employed to plan, procure, price and pay for system services leading up to real time.

Frameworks or mechanisms to provide for some system services may be designed to operate in one time frame, but they will inevitably impact decisions made by the operator, participants, investors or other stakeholders in different time frames. For example, a service such as system strength, which is currently typically delivered by capital intensive infrastructure, may be procured through a framework that signals investment months, or even years, in advance. However, the system strength provider will be making the investment on the basis that it will be able to provide the system strength service in real time.

In contrast, services that are provided as a by-product of electricity generation or that can be mobilised in seconds or minutes, such as frequency control, might be procured through a framework or mechanisms designed to value and pay for the service within real-time time frames. But the real-time value (and the change in that over time) will impact the medium and long term decisions of providers of that service.

Furthermore, frameworks could be designed to procure the same service covering more than one time frame, for different reasons. For example, one framework might provide a signal or payment for minimum, essential levels of a service many years in advance to make sure the service is provided (or there is time to make alternate arrangements if it is not) - and that participants are confident in this service being provided. A separate framework might be developed to signal and pay for additional amounts of the very same service closer to real time, in order to "fine tune" and take into account the dynamic nature of the electricity system and so conditions at that point in time.

In each case, the *need* for the service along with the *specific characteristics* of the service itself, and of the potential providers of that service, need to be evaluated to understand when

23 Although, monitoring of the supply/demand balance in longer, investment time frames is also undertaken.

services should be planned, procured, priced and paid for to deliver the most efficient outcome for consumers and the power system.

3.2 Three work streams: dispatch, commitment and investment

As outlined in the section above, system services may be more appropriately procured across different time frames depending on the nature of the service requirement and of the potential providers of that service, although there are interactions between the time frames and services. The six rule change requests discussed in this paper, along with the *Incentives for primary frequency control* rule change request already under way, each propose specific solutions that would operate predominantly within a specific time frame.

The AEMC has used the proponent's proposed solutions to group the rule change requests into three time frame-based "work streams" to allow common issues to be considered.

However, as discussed further below, when assessing each rule change request, it will also be necessary to think about the procurement of each service across the other time frames. Establishing work streams based on the specific solutions proposed by the proponents is merely one way of grouping the rule change requests and provides a useful starting point for consultation, however it does not necessarily define the outcome of any rule change that might be made in response to the rule change requests.

The three work streams are:

Dispatch work stream

The dispatch work stream will consider the rule change requests where the solution proposed involves co-optimising services as part of the dispatch process with participants making short-term inter-temporal decisions between dispatch intervals to meet system needs. The two rule change requests being considered in this work stream are:

- Infigen Energy — *Fast frequency response market ancillary service* (ERC0296)
- AEMO — *Primary frequency response incentive arrangements* (ERC0263) — initiated in September 2019

Commitment work stream

The commitment work stream will consider the rule change requests where the solution proposed involves committing or procuring the service ahead of the period for which there is a forecast need for the service. The three rule change requests that will be considered as part of this work stream are:

- Infigen Energy — *Operating reserves* (ERC0295)
- Delta Electricity — *Ramping services* (ERC0307)
- Delta Electricity — *Capacity commitment mechanism for system security and reliability services* (ERC0306)

Investment work stream

The investment work stream will consider the rule change requests where the solution proposed involves services that would be procured more than a few months ahead of the period it is needed. The rule change request that will be considered as part of this work stream is:

- TransGrid — *Centralised system strength provision* (ERC0300)

The TransGrid rule change request in the investment work stream will be progressed alongside the AEMC's *System strength investigation* given the number of common issues also being explored in that review. The Commission has also received a rule change request from Hydro Tasmania on *synchronous services markets* (ERC0290) which will also be progressed alongside the AEMC's system strength investigation. While the proposed synchronous services market relates to dispatch time frames, we consider it appropriate to be considered here given that it has implications for the investment in assets for the provision of synchronous services, which aligns with the issues being considered in the system strength review and TransGrid rule change**.**

3.3 System services will be considered across all time frames

Figure 3.1 provides a snapshot of the three work streams. It highlights the predominant time frame identified in each rule change request, as part of the proposed solution. However, Figure 3.1 also shows a range of other issues to be considered across all time frames for all rule change requests.

The AEMC will consider how each service identified in each rule change requests could be planned, procured, priced and paid for across *all* time frames, not just the predominant one identified in the solution proposed in each rule request. Any new frameworks developed in response to the rule change requests will be focused on delivering the most efficient outcomes for consumers, having regard to outcomes across all time frames.

Figure 3.1: Issues to be considered across all time frames for the provision of system services

Work stream	*Rule change request*	*Issues to be considered in investment timeframe*	*Issues to be considered in commitment timeframe*	*Issues to be considered in dispatch timeframe*
Dispatch	*AEMO – Primary frequency response incentives (ERC0263)*	Specification of the service Specification of any mandatory obligations	Commitment of synchronous generation determines quantity of PFR	Could potentially be co-optimised with energy and FCAS at dispatch (if included in the service)
	Infigen Energy – Fast frequency response market (ERC0296)	Specification of the service Long-term procurement for non-credible contingencies	Providers of FFR are unlikely to require commitment	Co-optimised with energy and FCAS at dispatch
Commitment	*Delta Electricity – Capacity commitment mechanism for system security and reliability services (ERC0307)*	Market participant planning	Some Service providers require a commitment decision	Payment may depend on 5-minute interval prices
	Delta Electricity – Introduction of ramping services (ERC0397)	Market participant planning Long-term procurement (e.g. RERT)	Some Service providers require a commitment decision	Co-optimised with energy and FCAS at dispatch
	Infigen Energy - Operating reserve market (ERC0295)	Market participant planning Long-term procurement (e.g. RERT)	Some Service providers require a commitment decision	Co-optimised with energy and FCAS at dispatch
Investment	*TransGrid – Efficient management of system strength on the power system (ERC0300)*	Planning, building or long-term contracting with synchronous services	Relying on directions/constraints for any sudden service shortfall	Scheduled/operated by AEMO and TNSPs
	Hydro Tasmania – Synchronous services markets (ERC0290)	Determination of impacts on security constraints	Determination of impacts on security constraints	Co-optimised with energy and FCAS at dispatch
	AEMC system strength investigation (EPR0076)	Obligations on AEMO and NSPs for system strength planning	Consideration of operation measures and directions to provide residual system strength requirements	Consideration of how system strength is accounted for in pre-dispatch
Key:	*Proponent's solution functions predominantly over the dispatch timeframe*	*Proponent's solution functions predominantly over the commitment timeframe*	*Proponent's solution functions predominantly over the Investment timeframe*	*Proponent's solution functions over no identifiable timeframe. This rule change request will initially be considered as a part of the investment work stream.*

Source: AEMC

QUESTION 3: **THREE WORK STREAMS: DISPATCH, COMMITMENT AND INVESTMENT**

1. Do stakeholders agree with the AEMC's approach to grouping the rule changes, at least for initial consideration?
2. Do stakeholders believe that Figure 3.1 captures the key issues to be considered for each rule change in each time frame?
3. Do stakeholders have views on whether/which services should be procured in certain time frames and not others?

4 ASSESSMENT FRAMEWORK

This chapter sets out the AEMC's framework for assessment of the system services rule change requests, and discusses a system services objective as a means of applying the National Electricity Objective (NEO) to system services trade-off decisions.

4.1 The NEO as the overarching objective

The Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[24] This is the decision-making framework that the Commission must apply.

The NEO is:[25]

> 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.

As discussed in the AEMC's guide to 'applying the energy market objectives',[26] the NEO is an economic concept and is intended to be interpreted as promoting efficiency in the long-term interests of consumers, which depends on the consideration of a specific set of variables, namely; the price, quality, safety, reliability and security of supply.

The AEMC must then consider the relevance of each variable to the rule change request or review on hand. This will be different in each project.

The Commission will assess the system security rule changes against a framework focussed on promotion of the long term interests of consumers.

The rule change requests discussed in this consultation paper include consideration of a spectrum of service design options — from market based mechanisms to more regulated approaches.

Following assessment against the NEO, the service design options and issues identified for consultation will then be considered in relation to the system services objective, which assesses whether each proposed service design option along this spectrum is likely to support the efficient operation, use and investment in system security capabilities in the NEM.

24 Section 88 of the NEL.

25 Section 7 of the NEL.

26 In 2019 the AEMC updated its Applying the energy market objectives - a guide for stakeholders document. More on this update and the background of energy market objectives can be found here: https://www.aemc.gov.au/regulation/regulation

4.2 The system services objective

Between them, the six rule change requests seek to address issues related to frequency control, voltage control, system strength, inertia and reserve services that are derived from the power system's transition to a lower emission generation mix.

In assessing these rule change requests, the Commission's role is to establish market frameworks that allow the most cost effective technologies to be deployed to minimise costs to consumers, while maintaining the reliability and security of the NEM power system. The AEMC considers it important to develop a specific approach to assessing the implications for the variables identified in the NEO – the price, quality, safety, reliability and security of supply — in a manner that is robust and relevant to the particular considerations arising in these rule change requests.

In order to guide this, we have developed a'system services objective' to use in relation to the assessment of these rule change requests. It reflects the trade-offs decisions that are expected when considering issues related to the provision of system services.

The **system services objective** seeks to:

> Establish arrangements to optimise the reliable, secure and safe provision of energy in the NEM, such that is it provided at efficient cost to consumers over the long-term, where 'efficient cost' implies the arrangements must promote:
>
> - efficient short-run operation of,
> - efficient short-run use of, and
> - efficient longer-term investment in,
>
> generation facilities, load, storage, networks (i.e. the power system) and other system service capability.

In clarifying the system services objective:

- **Promoting efficient operation** refers to factors associated with the ability of the service design option to achieve an optimal combination of inputs to produce the demanded level of the service, at least cost i.e. for a given level of output, the value of those resources (inputs) for this output are minimised.
- **Promoting efficient use** refers to factors associated with the ability of a service design option to allocate limited resources to deliver a service, or the right combination of services, according to consumer preferences (or system need). This may include allocating resources between the provision of multiple services, to achieve an efficient mix of overall service provision. It may also require consideration of meeting multiple system needs, including security, reliability, and resilience.
- **Promoting efficient investment** refers to factors associated with the ability of the service design option to continue to achieve allocative and productive efficiencies, over time. This means developing flexible market and regulatory frameworks, that can adapt to future changes. This involves the following considerations;

a. It is likely that the technologies that *provide* system services, as well as the technologies that drive the *need* for these services, will change significantly over time.

b. Technical understanding of these services will also change over time.

c. The robustness of service design options to climate change mitigation and adaptation risks will also contribute to dynamic efficiency over time.

Achieving dynamically efficient outcomes, given these attributes, will require flexible regulatory frameworks. The design of these frameworks should show explicit regard for how best to facilitate investment in the operation and use of system services over time, and how allocative and productive efficient outcomes in the short run can be maintained into the future.

QUESTION 4: **THE SYSTEM SERVICES OBJECTIVE**

1. Do stakeholders agree with the AEMC's proposed system services objective being used to assess these rule changes? If not, how should it be amended or revised?

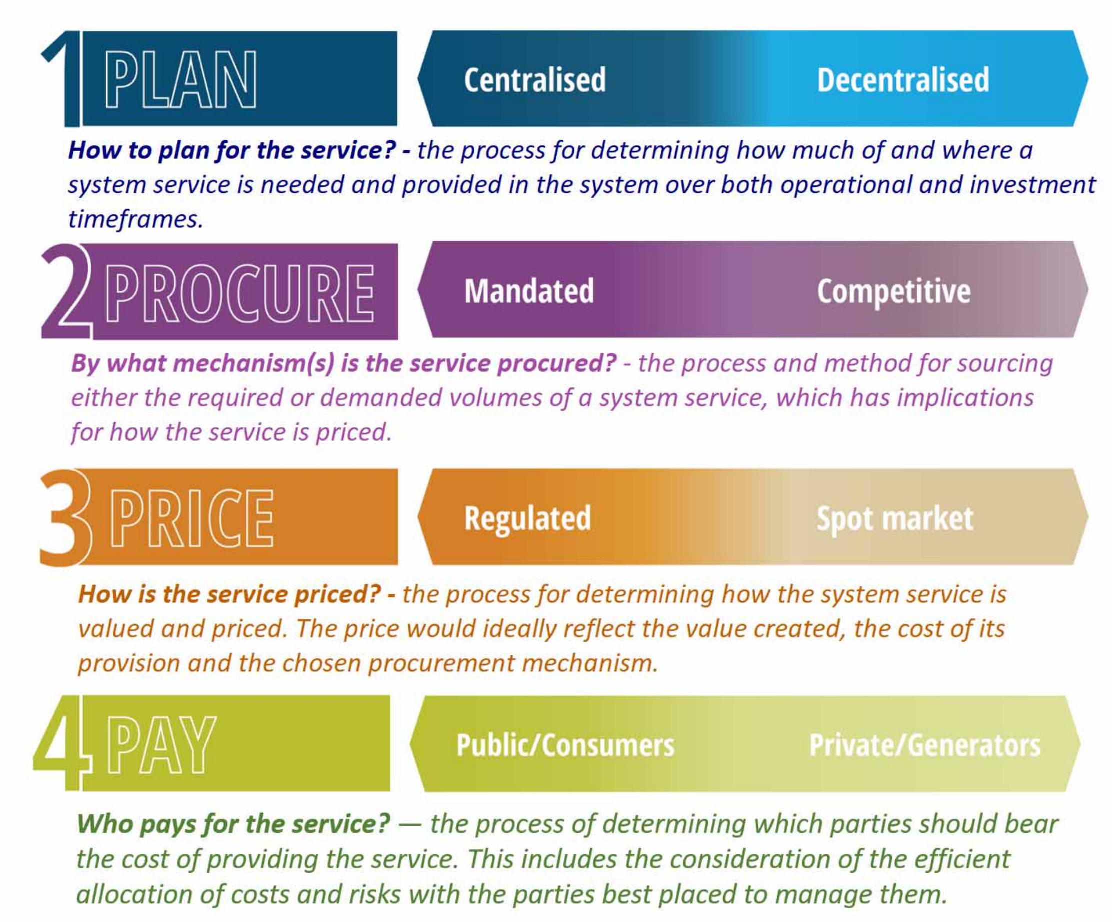
4.3 The planning, procuring, pricing and payment service design framework

The system services objective is used to assess service design options developed through the '4Ps' service design framework. This framework was first developed in the Discussion paper published for the *Investigation into system strength framework in the NEM*.[27]

In that paper, the Commission described the development of new market and regulatory frameworks based on thinking about how system services can be planned for, procured, priced and paid for. Within these categories, there exist a range of options, which are explored in the figure below:

27 More on this investigation can be found at the following link, as well as on page 56 of the discussion paper: https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem

Figure 4.1: Considerations for Planning, Procuring, Pricing and Paying for a system service



Source: AEMC

> QUESTION 5: **THE PLANNING, PROCURING, PRICING AND PAYMENT SERVICE DESIGN FRAMEWORK**
>
> 1. Do stakeholders agree with the '4Ps' service design framework being used to design these rule changes?

4.4 Principles for assessment

Each rule change request will be assessed in terms of whether it is likely to support and improve the security and reliability of the power system along with the effectiveness and efficiency of frameworks for the provision of system services. In particular, it will consider issues similar to the following principles, which each on their own contribute to the overall satisfaction of the system services objective:

- **Promoting power system security and reliability:** The operational security of the power system relates to the maintenance of the system within pre-defined limits for technical parameters such as voltage and frequency. System security underpins the operation of the energy market and the supply of electricity to consumers. Reliability refers to having sufficient capacity to meet consumer needs. It is therefore necessary to have regard to the potential benefits associated with improvements to system security and reliability brought about by the proposed rule changes, weighed against the likely costs.
- **Appropriate risk allocation**: The allocation of risks and the accountability for investment and operational decisions should rest with those parties best placed to manage them. The arrangements that relate to system services should recognise the technical and economic characteristics and capabilities of different types of market participants to engage with the system services planning, procurement, pricing and payment. Where practical, operational and investment risks should be borne by market participants, such as businesses, who are better able to manage them.
- **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.
- **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. Where practical, 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 required, while not imposing undue market or compliance costs.
- **Transparent, predictable and simple:** The market and regulatory arrangements for frequency control should promote transparency and be predictable, so that market participants can make informed and 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 6: **PRINCIPLES FOR ASSESSMENT**

1. Do stakeholders agree the principles proposed for assessing the rule change requests are appropriate? If not, which should be amended, excluded or added?

4.5 Making a more preferable rule

Under s. 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

4.6 Making a differential rule

From 1 July 2016, the NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in regulations made under the NT legislation adopting the NEL.[28]

Under those regulations, only certain parts of the NER have been adopted in the NT.(See the AEMC website for the NER that applies in the NT.)

Under the Northern Territory legislation adopting the NEL, the Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, a different rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule. A differential rule is a rule that:

- varies in its term as between:
  - the national electricity system, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

For the most part, the proposed rules that are the subject of the six rule change requests are likely to relate to parts of the NER that do not apply in the Northern Territory (i.e. chapters 3 and 4 of the NER), however, the Commission will continue to assess the additional elements required by the Northern Territory legislation in further proceeding with the rule change requests.

28 National Electricity (Northern Territory) (National Uniform Legislation) Act 2015.

5 THE RULE CHANGE REQUESTS

This chapter summarises the issues raised and the solutions proposed by Infigen Energy, Delta Electricity, Hydro Tasmania and TransGrid in their respective rule change requests. Chapters six through eight provide further discussion on common themes raised by the rule change requests in relation to the provision of system services.

5.1 Infigen Energy — *Fast frequency response market ancillary service* (ERC0296)

On 19 March 2020, the AEMC received a rule change request from Infigen Energy to amend the NER to introduce two new FCAS markets into the NEM for the provision of fast frequency response (FFR). The rule change request did not include proposed rule drafting.

5.1.1 Problem statement

In its rule change request, Infigen identifies that inverter-based generating technologies are displacing synchronous thermal generators at certain times of the day and, in some cases, contributing to early retirement.[29] Broadly, this is impacting the ability to control power system frequency in two ways:

- **RoCoF is increasing** as system inertia declines. As synchronous inertia in the power system decreases, the rate of change of frequency (RoCoF) following contingency events increases.[30] If inertia declines to the point where RoCoF is too fast, existing protection systems including FCAS will not be able to adequately arrest system frequency to prevent load shedding following contingency events.
- **Variability and unpredictability are increasing.** Variability in the operation of wind and solar generators as well as more frequent and intense weather events are leading to new modes of network failure, with contingency events more likely and their impacts harder to predict.

Higher RoCoF increases the need for a faster acting frequency response to meet the requirements of the power system frequency operating standard. Fast-acting technologies can provide their full response within milliseconds, which could better manage risks associated with system frequency in a low inertia system, including the management of RoCoF. Infigen states:[31]

> While FFR does not (currently) avoid the need for physical inertia, it provides for a broader operating envelope for the grid — allowing for operating with larger contingency events at lower levels of inertia.

29 Infigen Energy Limited, *Fast frequency response market ancillary service* — Electricity rule change proposal, 18 March 2020, p.1.

30 A contingency event is defined in the NER as: an event affecting the power system which AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units and/or transmission elements. NER cl.4.2.3(a)

31 Infigen Energy Limited, *Fast frequency response market ancillary service* — Electricity rule change proposal, 18 March 2020, p.1.

Infigen states that "AEMO does not currently appear to have the ability to procure fast-acting services in shorter time frames."[32]

5.1.2 Proposed solution

Infigen proposes that new ancillary service markets for FFR should be developed to provide AEMO with appropriate tools to manage system frequency following contingency events. The proposed FFR markets would also deliver a price signal to the market that would support the required investment in FFR capacity that would adequately mitigate the risk of managing future contingency events. Infigen states:[33]

> In our view, it is critical to address these issues now, and before they further impact the reliability of the power system or, alternatively, require greater and more disruptive market changes or interventions.
>
> [...]
>
> This will reduce the risk of major disruptions when possible but unexpected events occur.

Infigen proposes the introduction of two new contingency FCAS markets (raise and lower) for fast frequency response (FFR) services. FFR providers would respond to local frequency deviations and reach their full response within two seconds.[34]

AEMO would determine the specifications for the FFR service in the Market Ancillary Services Specification (MASS).[35] The market would be open to generation, loads and aggregators. AEMO would operate the markets similarly to how it operates existing contingency FCAS markets. FFR providers could participate in all FCAS contingency markets (6s, 60s, 5min) and would need to sustain their response for at least six seconds (in time to pass it on to the next 6s contingency FCAS market).[36]

If introduced, the volume of FFR, primary frequency response, regulation FCAS, contingency FCAS and inertia required to support the NEM would all be interrelated. Infigen considers that the volume of FFR service should therefore be calculated based on contingency size with consideration of the level of system inertia.[37]

According to Infigen, AEMO has indicated that some FFR resources can provide a response in less than 250ms, but Infigen suggests a response time of 0.5 to 2.0 seconds may be necessary to maximise market participation.[38]

32 Ibid, p. 1

33 Ibid, pp. 2, 4

34 Ibid, p.4.

35 The market ancillary service specification (MASS)is prepared by AEMO in accordance with clause 3.11.2(b) of the NER. It includes a detailed description of each of the market ancillary services together with relevant performance parameters and requirements.

36 Infigen Energy Limited, *Fast frequency response market ancillary service* — Electricity rule change proposal, 18 March 2020, p.5.

37 Ibid, p. 5

38 Ibid, p. 5

Costs and benefits

Infigen recognises that the procurement of FFR services will have ongoing operational costs as well as implementation costs which will need to be recovered from consumers. The implementation costs include those associated with changes to AEMO's NEMDE, dispatch and settlement systems.[39]

Infigen states that the operational costs associated with provision of FFR are expected to be offset by overall savings associated with more efficient dispatch of frequency response reserves.

Infigen suggests that introducing an FFR service could help reduce overall volumes of services (and costs) required to operate the system. Another benefit may be improved system resilience to (historically) non-credible events.[40]

Infigen notes that consumers would pay for the FFR service but would benefit from having additional tools to manage system security, resulting in improved system resilience, more efficient market operation and reduced need for other services.

5.1.3 Scope and issues raised

The issues raised by Infigen in its rule change request, *Fast frequency response market ancillary service*, include:

- Changes in generation technology are resulting in the reduction of system inertia and an increase in the rate of change of frequency following contingency events.
- The complexity of the power system is making the impacts of these contingency events harder to predict.
- AEMO's current procurement approach for contingency reserves does not explicitly target the provision of active power response within the range of FFR (sub-2 second response).
- The lack of a coordinated provision of inertia and FFR is negatively affecting system performance by increasing the risk of load shedding following contingency events.
- The efficiency of energy market dispatch could be improved through the market procurement of FFR, allowing for co-optimisation with inertia and contingency size.
- Arrangements for the procurement of FFR services will create a price signal to support efficient investment in future FFR capability to address the operational needs of the future power system.

These issues predominantly relate to the arrangements for the control of power system frequency following contingency events. This subject is discussed further in section 8.3.

39 Ibid, p. 6.
40 Ibid, p. 5

QUESTION 7: INFIGEN'S RULE CHANGE REQUEST, *FAST FREQUENCY RESPONSE MARKET ANCILLARY SERVICE* — ISSUES AND PROPOSED SOLUTION.

1. What are stakeholders' views on the issues raised by the Infigen in its rule change request, *Fast frequency response market ancillary service*?
2. Do stakeholders agree with Infigen's view that a change to the NER is required to encourage efficient provision of FFR services in the NEM following contingency events?
3. What are stakeholders' views on if there are any other issues or concerns that stakeholders have in relation to frequency control in the NEM as levels of synchronous inertia decline?
4. Do stakeholders consider there are alternative solutions that could be considered to improve the frequency control arrangements in the NEM for managing the risk of contingency events as the power system transforms?
5. Do stakeholders consider that 5-minute markets for FFR ancillary services likely to be effective and efficient in the global interconnected NEM and on a regional basis?
6. Do stakeholders consider Infigen’s proposal would provide adequate pricing signals to drive efficient investment in FFR capability in the NEM?
7. What are stakeholders' views on, if introduced, how the costs associated with any new FFR market ancillary services should be allocated?
8. What do stakeholders consider to be the likely costs associated with establishing two new ancillary service markets for FFR in the NEM?
9. Would are stakeholders' views on how the proposed solution may result in any substantial adverse or unintended consequences in the NEM?
10. Are there specific issues with FFR that stakeholders think should be addressed in the NER as part of the establishment of markets for FFR services?

5.2 Infigen Energy — *Operating reserve market* (ERC0295)

On 19 March 2020, the AEMC received a rule change request from Infigen Energy to amend the NER to introduce a dynamic operating reserve market to operate alongside the existing NEM spot and FCAS markets and help AEMO manage new and emerging operational challenges. The proposed operating reserve market would procure reserves 30 minutes ahead of time (with 15-minute call time) to align with the requirement to return the system to a secure operating state within 30 minutes.

The rule change request does not include proposed rule drafting.

5.2.1 Problem statement

In its rule change request, Infigen argues that there is a higher risk of contingency events due to more frequent extreme weather events (traditionally not classified as credible) and an increasingly wide range of new and unknown modes of failure ('unknown unknowns') that are difficult to predict and of which we have limited understanding. In addition, there are decreasing amounts of "operating reserves" (i.e. generation that is offered available into the market that is not dispatched, which creates in-market reserves that are capable of responding to changes in energy requirements) in the system due to transitioning generation stock and lack of incentives for new investment that has this capability.

While the current NEM-design has structures and mechanisms in place to predict and respond to changing system needs and to incentivise reserves to be available when the system needs them, Infigen argues these are no longer sufficient incentives to deliver enough/the right type of reserves to respond to today's contingencies. Without the right type of reserves available, Infigen notes that AEMO will increasingly rely on emergency (or intervention) mechanisms such as the RERT and directions to fill the gap.

5.2.2 Proposed solution

Infigen suggests that explicit incentives are required for operating reserves. Specifically, Infigen proposes the introduction of an operating reserve market comprising a dispatchable, raise-only service procured similar to contingency FCAS services — that is in real-time and co-optimised with the other energy market services to minimise adverse incentives. The proposed operating reserves have the following features:

- **Procurement trigger:** operating reserves could be procured at all times, or only during times of sufficiently tight supply/demand.
- **Volume:** set by the Reliability Panel or through guidelines and procedures and on the basis that the reserves procured would give AEMO the ability to respond to unexpected changes in supply or demand beyond those considered credible, but sufficiently targeted so that the benefits outweigh the costs. The Forecast uncertainty measure (FUM)[41] could be drawn upon when setting the volume.
- **Time frame:** 30 minutes ahead of time (with 15-minute call time) to align with requirement to return the system to a secure operating state within 30 minutes while allowing for a wide range of resources to offer reserves.
- **Eligibility:** any plant capable of producing operating reserves in T+30 time frame.
- **Market participation:** Resources enabled in the Operating Reserve market would be withdrawn from the energy market until called upon by AEMO in response to certain reliability criteria. However, operating reserves differ from out-of-market standing reserves because the number of suppliers and amount of reserves required would vary dynamically.

41 The FUM is the number of MW representing the quantity of error in reserves for which AEMO determines, at a certain confidence level, that the error will not exceed this value. In other words, it is the size of the adjustment to be made based on AEMO's modelling of reserve errors. FUM introduces a probabilistic element into the determination of lack of reserve (LOR) levels alongside the traditional deterministic approach. This allows for the impact of estimated reserve forecasting uncertainty in the prevailing conditions when calculating the LOR levels. Estimates are made on the basis of modelling past reserve forecasting performance for demand, output of intermittent generation and availability of scheduled generation.

- **Co-optimisation:** Operating reserves would be co-optimised such that the incentives of offering operating reserves does not adversely impact the spot market, the forward contract market or the associated activities and commitments of plant offering reserves.
- **Price:** Reserves would paid the marginal 'availability' price when called (with the market price cap applied). It is expected that competition will keep prices at, or close to, zero when reserve levels are high and increase to reflect scarcity.

Costs and benefits

Infigen argues this dynamic operating reserve market will provide the following benefits:

- value (demand and supply-side) reserves before the supply-demand balance becomes critical thereby strengthening investment signals for new flexible dispatchable capacity, despite market and regulatory/government uncertainty
- provide AEMO with more confidence that if demand or supply deviates materially from pre-dispatch forecasts, there will be operating reserves available (over much longer time periods than FCAS markets provide) without further intervention
- provide a more efficient alternative to RERT procurement and directions, reducing interventions in the market
- reduce cyclical spot market outcomes that breach consumer (and therefore political) tolerances.

Infigen notes that on face value, an operating reserve represents a new cost to consumers. However, their expectation is that the cost will be negligible when operating reserves are in good supply, and during times when they are priced to reflect the need, procuring operating reserves will remove the need for RERT which has cost $35-52m per year.[42] To the extent it increases overall demand for flexible and dispatchable resources, there may also be flow-on effects to energy prices; this could be balanced by drawing additional resources into the market.[43]

Infigen suggests further investigation will be required to determine the near-term cost of operating reserve provision.

5.2.3 Scope and issues raised

This rule request seeks to address two main issues.

First, an increased need for operating reserves in the transitioning power system due to:

- increasing variability and uncertainty on both the supply and demand side leading to increasing uncertainty and variability in the system's ability to cover system needs under the existing framework (self-commitment/real time)
- declining operating reserves and other services that were previously provided for free
- new and a dramatically wider range of power system 'modes of failure'
- gaps in our understanding of how these failures will play out.

42 Infigen Energy Limited, Operating reserves — Electricity rule change proposal, 18 March 2020, p. 11

43 ibid.

Second, a lack of incentives within existing framework to invest in operating reserves due to:

- complexity (driven by demand and supply uncertainty) in predicting what's needed making commercial investment decisions more complex/risky.
- "random and capricious government interventions".[44]
- broken link between energy prices and power system needs.
- "missing money" during periods when operating reserves are needed.

These issues are discussed further and stakeholder feedback is sought in chapter 7 and section 9.2.

QUESTION 8: INFIGEN'S RULE CHANGE REQUEST, *OPERATING RESERVE MARKET*, ISSUES AND PROPOSED SOLUTION.

1. Do stakeholders agree with Infigen that tight capacity conditions and increasing uncertainty in market outcomes are problems that an operating reserve would address?
2. Are there alternative solutions that could be considered to address tight capacity conditions and increasing uncertainty in market outcomes?
3. Do stakeholders consider Infigen's proposal would provide adequate pricing signals to drive efficient use of and investment in operating reserve services now and in the future?
4. How do stakeholders think separate operating reserves arrangements would affect available capacity in the spot, contracts and FCAS markets now and in the future?
5. How do stakeholders think separate operating reserves arrangements would affect prices in the spot, contracts and FCAS markets now and in the future?
6. How could the design of an operating reserve market (e.g. criteria for eligible capacity) best support competitive outcomes both in the operating reserves market but also energy and FCAS markets?
7. What are the factors that should be considered when seeking to set and procure efficient levels of operating reserve?
8. Would Infigen's proposed operating reserve market result in any substantial adverse or unintended consequences in the NEM?
9. What are the costs associated with establishing an operating reserve market in the NEM? If introduced, how should these costs be allocated?
10. What kind of incentive/penalty arrangements would be necessary to be confident the operating reserves procured are available when needed?

5.3 Delta Electricity — *Introduction of ramping services* (ERC0307)

On 4 June 2020 the AEMC received a rule change request from Delta Electricity to amend the NER to introduce 30-minute raise and lower "ramping" FCAS services using the existing

44 Infigen Energy Limited, *Operating reserve market* — Electricity rule change proposal, 19 March 2020, p.4.

framework for FCAS market design. Delta suggests these ramping services would address the price volatility that exists when dispatchable generators ramp through their energy bid stacks in response to predictable, daily, high rates of change from solar ramping up and down.

The rule change request does not include proposed rule drafting.

5.3.1 Problem statement

In its rule change request, Delta argues that there is an imminent and growing problem in the sustained ramping requirements imposed on the NEM's fleet of scheduled generators to accommodate the total solar daily generation profile. Delta states that as the total volume of large and small-scale solar generation in the NEM increases, the rate of change of the solar output profile, as it ramps up and down each day, means that: [45]

> "in effect, scheduled fully dispatchable generators need to provide the inverse of the solar profile, as well as dealing with:
>
> - wind generation variability
> - coincident changes in the pattern of underlying consumption of electricity
> - any contingency events such as load shedding, generator trips or interconnector failure."

Delta indicates that at the present time, scheduled generators provide capacity to fill the inverse solar profile gap through the energy dispatch process in response to energy price signals. Delta notes that existing FCAS services (6 seconds, 60 seconds and 5 minutes) can respond to short term changes in solar output, however the quantities of existing FCAS may become exhausted before the ramping requirement is over.

Delta shows that the total solar rate of change currently exceeds 1300MW per half-hour, and can remain at high rates of change for up to two hours.[46] Delta expects these trends to grow over time. The key problem identified by Delta is that the predictable, daily, high rates of change from solar can lead to increased price volatility and potential AEMO interventions. Delta acknowledges that price volatility is not an inherently adverse outcome and may provide incentives for available capacity to respond to the growing ramping need. However, Delta suggests that there may be a more sustainable approach.

5.3.2 Proposed solution

Delta has proposed the introduction of new 30-minute raise and lower "ramping" FCAS services using the existing framework for FCAS market design. Delta suggests that a visible market for ramping services will provide a more sustainable alternative to the current process where generators ramp through their energy bid stacks to signal value through volatility.[47]

Key features of the proposed new services and framework include:

45 Delta Electricity, *Introduction of ramping services* — Electricity rule change proposal, 4 June 2020,p.6.

46 ibid.

47 ibid p. 10

- The services would be procured from dispatchable in-service generators to respond quickly to significant and sustained changes in the output of VRE.[48]
- The services would be procured through a similar dispatch and settlement process to existing FCAS raise and lower services but with provision for generators to offer (perhaps three) incremental rates of change at different prices to reflect incremental costs such as increased wear and tear on the generating unit.[49]
- AEMO would determine the half hour by half hour ramping requirement in pre-dispatch as VRE generation shifts with changes in weather and insolation conditions.[50]
- Eligible generators would be determined by AEMO on the basis of their ability to provide the new raise and lower services and market design and settlement would be similar to existing FCAS raise and lower services.[51]
- Market participants providing the new 30-minute raise or lower services would not be prevented from bidding into the other FCAS markets as long as they can comply with their obligations in each market.[52]

Delta indicates that the new services would offer a "potentially more sustainable and less volatile price discovery mechanism that will provide a more orderly glide path for the exit of synchronous generators that presently provide this service. At the same time, the new services would provide a price signal for alternatives such as demand response and storage technologies such as hydro, battery and hydrogen that may, in the long term, form the bulk provision of this service.[53]

Delta notes that this proposal relates to Delta’s separate capacity commitment mechanism for system security and reliability services rule change (see section 5.4 below) as some types of generation, in particular slow-start thermal generators need to be committed ahead of time if they are to be available to provide their full range of system security and reliability services, including the new 30-minute raise and lower services. Generating units which are committed and operating at minimum load will be capable of ramping faster.

Costs and benefits

Delta indicates that its proposed new ramping product would support a more orderly transition to a high VRE NEM through more predictable and manageable prices, avoiding price shocks for customers (Delta notes that the energy market should settle at slightly lower levels with less volatility from the disaggregation of the proposed ramping service from energy dispatch). In addition, a transparent price signal for ramping services should yield short-run dispatch efficiency and over the long term, may provide an incentive for new technologies or demand-side response where those services are able to meet the ramping needs.

48 ibid p.1
49 ibid p.7
50 ibid p.7
51 ibid p.8
52 ibid p.9
53 ibid p.10

Delta has indicated that on face value, paying for a new ramping service represents a new cost in the market, however this cost may be negligible (at least initially while scheduled generation is in good supply) as it is simply the price of a service that was previously provided at a cost embedded in the energy market. The cost could be expected to rise over time if existing scheduled generators withdraw from the market and are not offset by new, equivalent capability.[54]

5.3.3 Scope and issues raised

Delta's rule change request seeks to address increase in price volatility and possible AEMO interventions which may be caused by the large and increasing rate of change in electricity output that occurs when the total solar capacity in the NEM increases in the morning and decreases in the afternoon. Delta suggests that it is up to the balance of the NEM generating portfolio, in particular the fleet of committed scheduled generators, to fill the gap and that they do so by ramping through their bid bands signalling value through price volatility.

QUESTION 9: DELTA'S RULE CHANGE REQUEST, I*NTRODUCTION OF RAMPING SERVICES,* ISSUES AND PROPOSED SOLUTION.

1. Do stakeholders agree with Delta that price volatility that occurs when dispatchable generators ramp through their energy bid stacks in response to predictable, daily, high rates of change from solar ramping up and down is a problem that needs addressing?
2. Do stakeholders think that a new raise and lower 30-minute FCAS would address the price volatility at these times? Are there alternatives that could be considered to address this problem?
3. Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in ramping services than existing price signals and information provided through the PASA and pre-dispatch processes?
4. How do stakeholders think a separate 30 minute ramping product would affect available capacity in the spot, contracts and FCAS markets now and in the future?
5. How do stakeholders think a separate 30 minute ramping product would affect prices in the spot, contracts and FCAS markets, now and in the future?
6. How could the design of a ramping FCAS product (e.g. criteria for eligible capacity) support competitive outcomes both energy and FCAS markets?
7. What are the factors that should be considered when seeking to set and procure efficient levels of ramping services?
8. Would Delta's proposed new 30-minute raise and lower FCAS products result in any substantial adverse or unintended consequences in the NEM?
9. What are the costs associated with establishing new 30-minute raise and lower FCAS products in the NEM? If introduced, how should these costs be allocated?

54 ibid p.10

> 10. What kind of incentive/penalty arrangements would be necessary to be confident the new 30-minute raise and lower FCAS products procured are available when needed?

5.4 Delta Electricity — *Capacity commitment mechanism for system security and reliability services* (ERC0306)

On 4 June 2020 the AEMC received a rule change request from Delta Electricity to amend the NER to introduce an ex-ante, day ahead capacity commitment mechanism and payment to provide access to operational reserve and any other system security or reliability services that AEMO may require to meet its security and reliability objectives.

The rule change request does not include proposed rule drafting.

5.4.1 Problem statement

In its rule change request Delta argues that as the instances and duration of very low spot market prices increase, non-peaking dispatchable capacity will seek to minimise financial losses by decommitting capacity, both intra-day and potentially for a few days under high VRE conditions. This means that the decommitted plant would not be available, as and when required to meet the energy and system services needs of the transitioning NEM and as a result, the NEM will more frequently experience periods of shortfalls in system security and reliability services.

Whilst AEMO can intervene in the market and direct scheduled generators to recommit to address these shortfalls, Delta suggests that the NEM will benefit from AEMO having access to a market-based alternative to its powers of direction.

Delta indicates that the risk of decommitted coal plant being unavailable are greater due to the fact that they take more time, and are also less predictable than other plant when attempting to restart and synchronise. It suggests that the services provided by these non-peaking dispatchable generators are likely to be necessary, at least for a period of time, to facilitate the transition to renewable energy. Without this capacity, Delta considers that the NEM will face reliability and security challenges as the amount of renewable capacity increases.

5.4.2 Proposed solution

Delta suggests that additional certainty and incentives are needed to ensure non-peaking dispatchable capacity can remain in operation during periods when it would otherwise de-commit.

Specifically, Delta has proposed the introduction of an ex-ante capacity commitment mechanism and payment to keep non-peaking dispatchable generators online at their minimum safe operating level (MSOL). The proposal would include using an ahead market approach which, combined with Delta's proposal for a new 30-minute raise and lower ramping service (see section 5.3 above) will mean a minimum level of operating reserve is available in the NEM to:

- meet the peak demand under conditions where variable renewable energy (VRE) output is limited
- respond to large changes in VRE output
- provide system service such as inertia, FCAS and voltage control.

Key components of Delta's capacity commitment mechanism are:

- day-ahead commitment of dispatchable capacity, at a level set by AEMO to ensure peak demand (excluding variable renewable energy (VRE)) can be reliably met. This will occur as part of the day-ahead pre-dispatch forecasting process.
- the in-service dispatch capability will be drawn on to respond to rapid changes in VRE. It would be paid whenever it is dispatched at MSOL. The amount would cover expected losses associated with low prices as seen on AEMO's 7-day pre-dispatch.
- generators would guarantee to commit their coal/gas fired boiler synchronous units for either an entire day or for specific trading intervals during the day rather than via a half-hour ahead market for reserve.

The proposal has the following additional features:

- The operating reserve requirement in a region for the day ahead would be determined by AEMO and be equal to:
  - Region daily maximum demand *plus*
  - the contingency reserve relevant to the region *minus*
  - forecast interconnector import capability at the time of maximum demand *minus*
  - non-committed fast start scheduled capacity within the region at the time of maximum demand *minus*
  - aggregate Minimum Safe Operating Level of the committed scheduled capacity within the region at the time of maximum demand.
- an operating reserve generating unit must have relevant capabilities e.g be able to provide inertia, system strength, reliability services or they must be able to ramp up/down at a controlled rate.
- operating reserves could be paid for either through a causer pays model i.e. VRE generators pay on some pro-rated basis, or a system cost (like an ancillary service) on retailers that would be passed through to consumers.

Delta considers that AEMO is best positioned to determine the details of an appropriate methodology for the assessment of regional operational reserve (and all other SSRS) requirements. AEMO would be required to publish an operational reserve requirements guideline that describes the considerations and detailed methodology AEMO applies in performing its operational reserve assessment and similar guidelines for all other SSRS.

Costs and benefits

The key benefit Delta identifies in its rule change request flows from AEMO being able to procure the system services it needs at a lower cost than the value of customer reliability (VCR).[55] Delta suggests that the additional dispatchable capacity kept in service because of the proposed ahead commitment mechanism should contribute to more competitive energy pricing in the spot and contract market.[56]

Delta also suggests that the proposed capacity commitment mechanism will result in reduced system security costs including FCAS, directions and RERT costs and over the longer term the transparent price signal will incentivise investment in new technology, increasing competition and putting downward pressure on electricity prices.[57]

Delta considers that while the proposed rule change is not cost-free the costs are very modest given most of the time the cost of operational reserve will be zero but will acquire a value at times of very high system demand or when very high levels of VRE drive some generators to de-commit[58]. Other potential costs noted by Delta include that VRE providers may face some additional VRE curtailment in the short term (offset by the fact that all participants in the NEM benefit from the improved security of the system), and that AEMO and potential participants in the proposed new mechanism would incur implementation costs.[59]

5.4.3 Scope and issues raised

This rule change request seeks to address the risk of decreasing levels of dispatchable capacity available to respond to system reliability or security challenges at the same time that the need for the reserves and system services provided by dispatchable capacity increases.

It also seeks to address the issue of "aheadness", that is that some sort of ahead commitment may be necessary to provide sufficient incentives to market participants to make system services available, and to provide sufficient confidence to the system operator, and other stakeholders that essential system services *are or will be* available when customers and the power system needs them.

These issues are discussed further and stakeholder feedback is sought in chapter 7 and section 9.2.

55 Delta Electricity, *Capacity commitment mechanisms for system security and reliability* — Electricity rule change proposal, 4 June 2020,p.26.

56 ibid p.28

57 ibid p.26-27

58 ibid p.28

59 ibid p.29

QUESTION 10: DELTA'S RULE CHANGE REQUEST, *CAPACITY COMMITMENT MECHANISM FOR SYSTEM SECURITY AND RELIABILITY SERVICE,* ISSUES AND PROPOSED SOLUTION.

1. Do stakeholders agree with Delta that there is an increasing risk that capacity capable of providing reserves or services may not be available at times when the power system may need them to respond to unexpected events because of increasing incentives to de-commit?
2. Do stakeholders think that a mechanism to commit capacity one day ahead of time would deliver the reserves or services needed? Are there alternatives that could be considered to address this problem?
3. Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in reserves and system services?
4. How do stakeholders think Delta's capacity commitment payment would affect available capacity in the spot, contracts and FCAS markets now and in the future?
5. How do stakeholders think Delta's capacity commitment mechanism would affect prices in the spot, contracts and FCAS markets now and in the future?
6. How would a capacity commitment mechanism and payment affect entry, exit and competition in the NEM over the short and long term?
7. What are the factors that should be considered when deciding how much capacity to commit ahead of time?
8. Would Delta's proposed capacity commitment mechanism result in any substantial adverse or unintended consequences in the NEM?
9. What are the costs associated with establishing a capacity commitment mechanism in the NEM? If introduced, how should these costs be allocated?
10. What kind of incentive/penalty arrangements would be necessary to be confident that the committed capacity would be available throughout the commitment period and/or when called upon?

5.5 Hydro Tasmania — *Synchronous services markets* (ERC0290)

Hydro Tasmania submitted a rule change request on 19 November 2019 to amend the National Electricity Rules to create a synchronous services market.[60] These synchronous services include inertia, voltage control and fault level (system strength).

5.5.1 Problem statement

Hydro Tasmania notes the unprecedented number of AEMO directions for synchronous services to provide system security is not a long-term solution consistent with the NEO.[61]

60 Hydro Tasmania, *Synchronous services markets* — rule change proposal, 17 September 2019.

61 ibid, pp. 1-4.

The rule change request is presented as a low cost and relatively simple approach that could provide a more efficient long-term solution in support of the NEO.

Hydro Tasmania state that the absence of an explicit and transparent compensation mechanism for the provision of synchronous services prevents AEMO from issuing dispatch instructions to synchronous generators for the provision of these needed services. AEMO must instead intervene in the market through directions to dispatch synchronous generation to maintain system security.

5.5.2 Proposed solution

Hydro Tasmania proposes to address the shortage of "inertia and related services in the NEM" by integrating the dispatch of a "synchronous service" with the existing energy and FCAS spot markets.[62]

Hydro Tasmania propose to do this by changing the formulation of the constraints that are applied to the NEM dispatch engine (NEMDE). These reformulated constraints would allow the dispatch engine to find the lowest overall cost combination of synchronous services and non-synchronous generation, to deliver lower overall costs for consumers.

This is proposed to be achieved through the following:

- Amending the NER to create a new generator category of *synchronous service generator* (SSG). This would AEMO allow to reconfigure the dispatch engine such that relevant generator's online status (or circuit breaker status) be moved to the output side of AEMO's constraint equation. This allows these generators to receive a target to come online, with the circuit breaker status of a generator treated as a faux power station of 1MW capacity in NEMDE.
  - The use of the circuit breaker status is because the synchronous services (inertia, system strength and voltage control) are obtained by the generator being online, rather than being provided in proportion to its active power/energy (MW) output.[63]
- Having generators provide two additional fields in their spot market bids to AEMO indicating cost and availability of synchronising units online.
- **Proposed SSG settlement** — Hydro Tasmania is proposing that generators be paid based on their bid price for providing synchronous services rather than the spot price.
- **Dispatch conditions** — SSGs would be dispatched if doing so provided lower priced outcomes for consumers compared to the constraint binding. The price offered by SSGs for their synchronous services will contend with the cost of relieving the constraint and dispatching those generators in the constraint. The dispatch engine would instruct generators to be placed online where doing so reduces the market price.
- **Determining the costs and who pays** — AEMO would need to publish two prices for each service, one including the cost of SSGs and one without. This means prices:

62 Ibid, pp. 4-9.

63 For more information on this see Section 3.4.1 and 3.4.2 of AEMC's *System strength investigation: Discussion paper*, March 2020.

- excluding SSGs would work by existing principles, and would continue to be used for settlement of all generators, other than any dispatched SSG's.
- including SSGs would be determined by dividing the total payments to the SSG by the size of the load in the region in which the SSG is located. Loads would pay this price (in addition to the price of energy).

Hydro Tasmania presents simple scenarios in this request, to demonstrate that the price difference between the two prices may be very small, and hence not jeopardise contract market liquidity, or impose inefficient costs on consumers.

Costs and benefits

Hydro Tasmania recognises the implementation of its proposed synchronous services arrangement would have costs relating to updating of constraints in NEMDE. Market participants may also incur upfront costs associated with updating their bidding systems to provide AEMO with cost and availability information for synchronous units[64].

Hydro Tasmania consider that the benefits of the proposed change will come about through more efficient operation and utilisation of resources. It is envisaged that there would be less need for AEMO to intervene in the market operation through directions and inflexible constraints resulting in a more efficient market operation[65].

5.5.3 Scope and issues raised

The scope of the problem identified by the rule change request is very broad, reflecting the general nature of the problem statement regarding the need to actively co-optimise in dispatch, and provide remuneration to, providers of synchronous services.

This broad problem definition allows for consideration of a wide range of mechanisms to procure the services traditionally provided by synchronous generators, including system strength, inertia and reactive support.[66]

Reforms that introduce adjustments to NEMDE must consider the implications of these modifications. For example, the Hydro Tasmania rule change proposes to introduce constraints to enable the delivery of a synchronous service. Considerations should therefore include the extent to which these changes will impact on NEMDE, introduce complexity and create scenarios that may result in perverse outcomes.

QUESTION 11: HYDRO TASMANIA'S RULE CHANGE REQUEST, *SYNCHRONOUS SERVICES MARKETS,* ISSUES AND PROPOSED SOLUTION.

1. Do stakeholders consider this rule change proposal presents a viable model for the provision synchronous services?

64 Hydro Tasmania, *Synchronous services markets* — rule change proposal, 17 September 2019, p.3

65 ibid p.4

66 Hydro Tasmania, *Synchronous services markets* - rule change proposal, 17 September 2019, pp. 4-9.

a. Could this proposed model be used to provide the essential levels of system strength (and / or inertia and voltage control) needed to maintain security and the stable operation of non-synchronous generation?

b. Could this proposed model be used to provide levels of system strength (and / or inertia and voltage control) above the essential level required for security?

2. Do stakeholders consider that the creation of a synchronous services market could have any adverse impacts on other markets in the NEM? If so, what would these impacts be?
3. Would the proposed model set out in the rule change request efficiently price and allocate costs for synchronous services in the NEM ?
4. Do stakeholders consider the model set out in the rule change request would be capable of sending price signals sufficient to encourage new investment in synchronous capacity?
5. Do stakeholders consider the rule change provides an appropriate incentive mechanism for existing synchronous generators to make operational decisions to provide synchronous services ?
6. Do stakeholders consider the rule change provides the appropriate locational signals for the provision of synchronous generators to provide synchronous services ?
7. What do stakeholders see as the primary opportunities / limitations of the mechanism as proposed by Hydro Tasmania?
8. Would the model proposed in the rule change request enable effective competition in the market for the provision of synchronous services?
9. What suggestions do stakeholders have in relation to the first order changes that would be required in NEMDE to facilitate this proposal and any second order changes that may be required as a result of this rule change proposals' implementation?

5.6 TransGrid — *Efficient management of system strength on the power system* (ERC0300)

TransGrid has also submitted a rule change request to amend the National Electricity Rules to be more proactive in provision of system strength in the NEM.[67] The request proposes to abolish the "do no harm" obligation and amend the minimum system strength requirements. This follows issues with the existing system strength framework that have arisen since it was put in place in 2017.

5.6.1 Problem statement

TransGrid recognises system strength as an urgent issue to address in the NEM.[68] TransGrid identifies three principal issues with the current frameworks:

67 TransGrid, 2020, *Efficient management on system strength on the power system* — Rule change proposal, 27 April 2020.
68 ibid, pp. 5-9.

- The lack of ability to effectively coordinate solutions to address system strength issues across the 'do no harm' and minimum frameworks, as well as the lack of explicit linkages between the both system strength frameworks and other system services, particularly inertia services. This is because while all three frameworks interact, they are not formally connected, which creates the risk of feedback loops and inefficiencies.
- The additional time and cost for connection of new generation to the power system due to the system strength impact modelling and remediation requirements of the "do no harm" obligation.
- The slow, reactive nature of the minimum system strength framework, which leads to increased risks of costly interventions in the operation of the energy market. This is due to the difficulties faced by AEMO in undertaking effective forecasting, which has resulted in declarations of system strength (and inertia) shortfall/s when they already exist, rather than at least 5 years out as envisaged in the framework. This leaves the TNSP no time to procure the services before AEMO has to intervene in the market using constraints or directions.

The Commission recognised similar issues in Chapter 3 of its March 2020 Discussion paper for its *Investigation into system strength frameworks in the NEM*.[69]

5.6.2 Proposed solution

The TransGrid proposal involves:[70]

1. AEMO setting the system strength requirement for identified fault level nodes in the system. That is, AEMO will define the level of system strength is required for each sub-region in the NEM.
   - AEMO would retain responsibility for determining fault level nodes and the minimum fault level that is required at each node. This would be done in conjunction with TNSPs, as is currently the case through the minimum system strength processes.
   - A key difference with the current framework is that when setting these levels, AEMO would also have to account for the potential future impact of new generation (using the ISP) in setting the minimum fault level for each node.
2. An independent body (TransGrid proposes the Reliability Panel) would set a probabilistic planning standard, which would define how often TNSPs must be able to meet the required minimum levels of system strength. This standard could be similar in form to the current reliability standard of 0.002% unserved energy.
   - This standard could be applied global/NEM-wide, regionally for each TNSP, or on a nodal basis.
   - TNSPs would meet this standard through their normal planning processes including contingent projects for more time sensitive issues.
3. TNSPs are obligated to maintain these system strength levels to this standard for each node defined in their network.

69 AEMC, *Investigation into the system strength frameworks in the NEM: Discussion paper,* Chapter 3, March 2020.

70 ibid, pp. 10-18.

- TNSPs would be responsible for assessing if there is enough system strength provision to meet minimum levels in collaboration with AEMO. TNSPs can then provide the service either through network or non-network options to maintain the standard.

AEMO would also be able to declare system strength shortfalls as an NSCAS gap in cases that sufficient levels of system strength are not captured through longer term planning processes. AEMO would then act as procurer of last resort if the gap remained unmet by TNSPs.

TransGrid also proposes to amend the current minimum system strength framework such that it is integrated into TNSPs' ordinary planning and regulatory frameworks. That means that system strength would be an extension of the existing NER defined regulatory standards for network planning and operation. This would make system strength the same as those that exist for thermal capacity and for the provision of voltage control services.

This proposal abolishes the 'do no harm' framework. In its place, generator connection processes would still require each plant to negotiate and meet generation performance standards (GPS) to connect. TransGrid state this means that generators will not have to undergo the full impact assessment associated with the 'do no harm' obligation. TransGrid then state that this may result in them being penalised when trying to meet their GPS if they do not locate in optimal (strong) parts of the network. The proposal also expects the risk of constraints will provide a further locational signal.

Costs and benefits

In its rule change request, TransGrid notes a variety of possible benefits and costs to addressing system strength issues which TransGrid suggests, if considered in the manner it proposes, would yield a significant overall net benefit to system strength arrangements in the NEM.

TransGrid suggests an array of benefits[71] would result in quicker, cheaper connection and energisation, less market interventions and improved coordination of investment and augmentation decisions, which in turn would benefit final customers through reduced energy costs. The main benefits of the rule change include:

- The facilitation of more coordinated, scale-efficient delivery of system strength services.
- A more efficient balance of costs incurred on the market by having more shortfalls addressed by solutions achieved by system strength services as opposed to market interventions that manage the power system securely for short periods of time.
- The removal of impractical requirements on generators to deliver bespoke remediation schemes, allowing for more cost-effective grid connection and reducing unnecessary duplication of investment in service capability.
- Transmission networks will be able to operate more efficiently, as they will be empowered by more flexible arrangements to respond to rapid changes in system strength on the power system.

71 National Electricity Rule changes proposal, Efficient management of system strength on the power system, TransGrid, April 2020, p. 19.

TransGrid notes that the proposed changes would incur some material costs. These include:

- Administrative and development costs incurred on AEMO when setting minimum fault levels at defined notes and in developing a new fault level standard. TransGrid acknowledges some of this work has already been done, so costs may be reduced.
- Material costs incurred by TNSPs in procuring system strength services, however TransGrid notes that these incremental costs are likely to be lower than costs incurred by those incurred by other market participants when remediating system strength impacts in an uncoordinated manner.
- Additional administrative costs incurred by TNSPs in developing internal processes and frameworks required to implement the proposed changes.

5.6.3 Scope and issues raised

TransGrid propose to abolish the 'do no harm' obligation, and to amend the minimum system strength framework.[72]

This includes the provision of system strength to meet minimum power system requirements and additional system strength to streamline the connection of new non-synchronous generators. There is also implicit discussion of system strength provision for constraint alleviation.

The proposal also notes other aspects of the NER that the AEMC may wish to include in its considerations, including:

- Amending the regulatory (NER) definition of system strength, to focus on a technology neutral approach to allow for future innovative technologies to provide the service, like grid forming inverters.
- Generator technical performance standards and coordination of generation — particularly establishing a:
    - system strength performance standard — this would require generators to have a certain quality inverter in regard to system strength (typically in reference to the inverter's capability of functioning in low system strength environments)
    - process for renegotiating existing generators GPS to reduce generator impacts on system strength.
- Consideration of the best way to facilitate system strength services in distribution networks.

It also proposes that changing the minimum inertia framework should be made to align with any changes that may be made to the minimum system strength framework.

72 ibid, pp. 10-11.

QUESTION 12: TRANSGRID'S RULE CHANGE REQUEST, *EFFICIENT MANAGEMENT OF SYSTEM STRENGTH ON THE POWER SYSTEM, ISSUES AND PROPOSED SOLUTION.*

1. Do stakeholders consider that TransGrid’s approach address all issues related to system strength currently experienced in the NEM?
2. Do stakeholders consider that a system strength planning standard met by TNSPs would effectively and pro-actively deliver adequate system strength?
3. Do stakeholders consider TransGrid’s proposal will provide useful and timely locational and financial signals to new entrants?
4. Do stakeholders agree that the 'do no harm' obligations should be removed?
    a. If so, do stakeholders consider an alternative mechanism is required to regulate or incentivise the minimisation of a new connecting generator's impact on the local network and proximate plant?
5. What are stakeholder's views regarding generators' being required to make a financial contribution for provision of system strength services?
6. Would stakeholders be supportive of the ownership of existing private system strength assets being transferred to TNSPs, as suggested in TransGrid's rule change request?
7. Would the proposed, TNSP-led solution to system strength result in any adverse or unintended consequences for market participants in the NEM?

6 SYSTEM STRENGTH

The AEMC *System strength investigation's* March 2020 Discussion paper (the Discussion paper) explored and consulted on a number of issues related to system strength.[73] This Chapter builds on stakeholder submissions to the Discussion paper, and sets out some further analysis on how system strength can be more effectively and efficiently provided in the NEM.

The Discussion paper explored two issues that will also be particularly relevant to the consideration of the TransGrid and Hydro Tasmania rule changes set out in Chapter 5. These areas include:

- Definition of system strength, including the underlying problem statement and the resultant evolution of a regulatory service definition.
- Mechanisms for system strength provision above the essential level necessary for security.

6.1 Evolving the regulatory definition of system strength

This section discusses the development of a problem statement for system strength, and the potential evolution of the regulatory definition of system strength, both of which are being explored through the system strength investigation.

A more detailed problem definition will help in the development of an effective regulatory definition of system strength.

6.1.1 Problem definition

There was significant support for the AEMC to further evolve the system strength definition in stakeholder submissions to the Discussion paper*.* The AEMC found, through consultation with various stakeholders, that some ambiguity exists as to what services are encompassed by the term 'system strength'. For example, stakeholders hold differing views on the extent to which voltage stability standards should be considered as part of the definition of the system strength.

Using the definition of system strength to identify system strength services

A key complexity to be unpacked is whether, based on the problem statement and its broad components described below, it is possible to:

- consider system strength as a single service across all of these components
- develop an explicit unit of measurement for system strength.

Historically, fault level (expressed in MVA) has formed a proxy unit of measurement for system strength. However, while fault level may be an effective measure when considering fault management, this is only one component of the general concept described as "system strength".

73 AEMC, Investigation into system strength frameworks in the NEM: Discussion paper, March 2020.

Scope of issues — what does system strength do?

At a high level, the system strength problem scope can broadly be defined by reference to whether the power system's voltage waveforms are stable, under both normal and disturbance conditions. On this basis, AEMO currently defines the effect of system strength as:[74]

> *"the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance."*

Voltage stability is a broad concept, and can include a number of power system effects and outcomes. These occur both at the wide area, macro level of the power system generally, as well as at the narrow, micro level of the individual generating unit.

The system strength problem definition, and ultimately solutions to address this problem, need to apply to the operation of the power system as a whole, as well as down to the level of individual generating units.

On this basis, we have developed a working description of the *effects* of system strength on the power system, which we consider complements AEMO's definition. That is, we consider that system strength is relevant to:

the stability of voltage waveforms related to the interactions between generator equipment (synchronous or inverter-based) and the rest of the power system.

In other words, the current understanding of system strength, and its effects across the system, is that it is both:

1. The ability of the power system to maintain a stable voltage waveform, during both normal operation and following any change in the system.
2. A quality related to the electrical interactions between different components of the power system. This is dependent on factors like network impedance, the responses of synchronous machines, and the way that inverter connected generators behave.

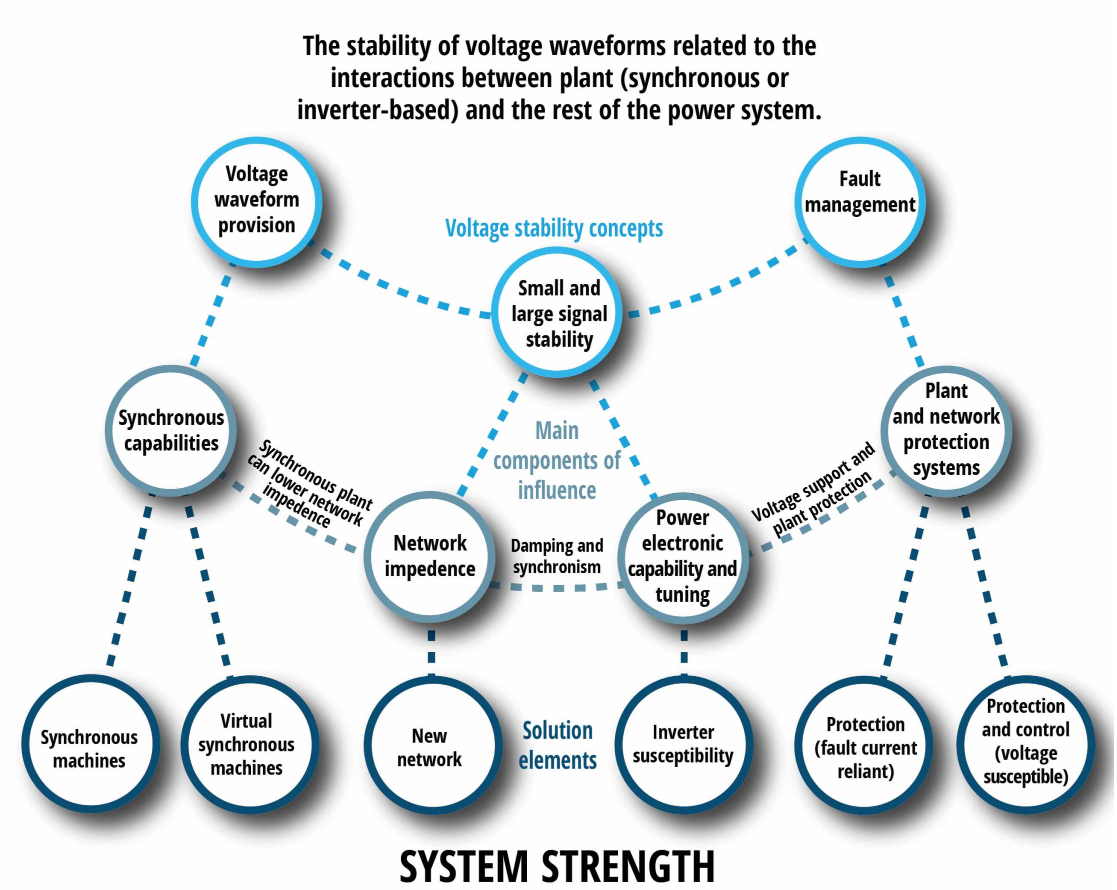
System strength is therefore characterised as a phenomenon that is influenced by different components of the power system in different ways. System strength is not solely provided or impacted by the isolated behaviour of individual plant.

Breaking down the system strength problem statement into its components

This problem statement discussed above describes what system strength "does" on the power system. However, this can then be broken down into three broad components, each of which has its own fundamental elements as shown in the figure below.

74 AEMO, Renewable integration study — stage 1 report, April 2020, p.50.

Figure 6.1: Breakdown of system strength



Source: AEMC

- **Voltage waveform provision:**
  - *'Synchronous capabilities'* – machines like synchronous generators and synchronous condensers can actively "supply" stable voltages, which in turn provide a stable reference for the local power system. This can also be provided by "virtual" synchronous machines, which are sometimes called grid forming inverters.
- **Large and small signal stability:**
  - *Low network impedance*. Impedance, which can be described as an AC circuit's equivalent of resistance, produces less voltage change for any change in the power system's current. So, a power system with lower impedance is usually more effective at keeping voltages stable.
  - *Stable, well-tuned inverter control systems* – well tuned inverter connected generators are better able to "hang on" to the power system following disturbances. This means these generators have a better chance of remaining connected following large disturbances, even if the system voltage is less stable. They also react less to

disturbances, such that these disturbances are not made worse. This helps prevent small disturbances growing and causing instabilities in the system.

- **Fault management:**
  - *Plant and network protection equipment* – Protection equipment limits the impact of faults, and helps prevent blackouts. However, some protection equipment requires a certain level of fault current to operate effectively.Some protection equipment is also susceptible to mal-operation in weak grids with volatile voltages.

6.1.2 Relevant rule change requests

The rule change requests from TransGrid and Hydro Tasmania along with Delta's rule change request, *Capacity commitment mechanism for system security and reliability services,* discuss new regulatory arrangements for the provision of system strength, which have implications of the system strength problem scope and definition as discussed above. These include:

- TransGrid's proposal explicitly discusses the need to evolve the Chapter 10 NER definition of *system strength services* to ensure technology neutrality in the provision of system strength.
- Hydro Tasmania proposed a new *synchronous service* be created, which implicitly includes system strength provision. It is unclear from the rule change request what exactly the *synchronous service* is and how its provision would be measured for market settlement.
- In its rule change request, *Capacity commitment mechanism for system security and reliability services,* Delta refers to system strength as one of the services that could be provided (along with operating reserves and other system services) through a day ahead capacity commitment schedule and payment for non-peaking synchronous generators.

Exploring the core problem definition of system strength is the initial step required to evolve the system strength definition. This definition will then form the basis on which these rule change proposals can be developed.

QUESTION 13: EVOLVING THE REGULATORY DEFINITION OF SYSTEM STRENGTH

1. Do stakeholders consider that the AEMC's working description of the effects of system strength, and related problem description of system strength and its components accurately represents all elements of system strength, as experienced in the NEM?
2. If not, are there other components of system strength that the AEMC should include?
3. What measures might be used to define system strength? Is fault level the only measure that can be used practically, or are other measures available?

6.2 Mechanisms to provide system strength, above the essential levels that are necessary for security

This section explores the fact that the current system strength frameworks do not value system strength levels above the minimum, security-critical levels.

Frameworks that require TNSPs to maintain minimum levels of inertia and system strength were put in place in 2017.[75] As discussed in the discussion paper, these frameworks do not place an explicit value on or incentivise proactive procurement of these synchronous services until a shortfall is declared by AEMO for a node/area.

Furthermore, these frameworks do not include a mechanism to value the procurement of synchronous services, such as system strength and inertia, above the minimum required to maintain system security. This can result in inefficient outcomes, particularly instances where large-scale constraints are applied on non-synchronous generation for the purposes of system security. The existing frameworks do not value the provision of additional services, even where this could result in more efficient dispatch outcomes and reduce overall wholesale costs.

6.2.1 Scope to develop new mechanisms

There is some value in the provision of additional system strength above the essential levels required to maintain system security. This additional system strength could alleviate constraints on non-synchronous generation, increase hosting capacity and provide additional resilience to non-credible contingencies.[76] Therefore, mechanisms that provide additional amounts of system strength, above the essential level required to maintain security, may provide significant market benefits and enhance power system resilience.

In the Discussion paper, *Investigation into system strength frameworks in the NEM*, the Commission identified it will examine a range of mechanisms to efficiently facilitate and incentivise provision of additional levels of system strength.[77] This will include consideration of how these mechanisms align with the core considerations of the overall framework. For example, how the mechanism would consider planning, procurement, pricing and payment.

Alongside these considerations we will be mindful of the complexity, practicality, and the extent to which these mechanisms efficiently allocate risk and responsibility in operational and investment time frames.

The Discussion paper presented some potential models for the provision of system strength. In summary, these were:

- Model 1: Centrally co-ordinated — A centrally co-ordinated approach, where networks and AEMO play a central role.

75 National Electricity Amendment (Managing power system fault levels) Rule 2017 No. 10

76 This concept of "hosting capacity" refers to the ability of the network to facilitate the effective connection of, and export of energy by, as many generators as is efficiently possible. Importantly, it not only refers to the active provision of system strength on the network to support more connections, but also ensuring that this system strength is "used" as efficiently as possible by all generators. That is, generation control equipment should be calibrated in a manner such that it "uses up" as little available system strength as possible.

77 AEMC, *Investigation into system strength frameworks in the NEM* — Discussion paper, 26 March 2020.

- Model 2: Market base decentralised — A decentralised approach, where competitive forces play a central role in coordination and delivery.
- Model 3: A mandatory service provision approach — A more centralised model, where all generators are required to bring an "active" contribution to system strength.
- Model 4: An access standard approach — A more centralised approach where all generators are required to have a "passive" system strength withstand capability.

The models were intended to describe the range of different options that can be considered and are not necessarily mutually exclusive. Elements of each model may be combined to deliver hybrid models.

6.2.2 Relevant rule change requests

The models outlined in the Discussion paper not only present possible mechanisms to procure system strength to meet essential levels, but also to procure above those levels. For example, a centrally co-ordinated model has the potential to provide both essential and additional levels of system strength and decentralised market-based mechanism could potentially leverage additional levels above those deemed essential.

The Commission has received rule change requests from Hydro Tasmania, TransGrid and Delta Energy that reflect, to some degree, two of the models outlined by the Commission in the Discussion paper. Both rule change requests present potential opportunities to procure levels of system strength above the essential required for secure operation.

For example:

- Model 1: Centrally coordinated mechanism – The TransGrid rule change request proposes to provide system strength through a TNSP investment led, centrally coordinated model. This model is intended to deliver levels of system strength above the minimum for security, including to provide hosting capacity for new connections. This would be achieved by coordinating the provision of additional system strength by leveraging scale efficient solutions.
- Model 2: Decentralised market-based mechanism:
  - The Hydro Tasmania rule change request proposes to provide system strength through a market-led, operational, decentralised model. This approach could be used to deliver levels of synchronous services, which include system strength, above the minimum required for security. This would be achieved by sourcing these services from the market.
  - Similarly, the Delta energy rule change request (the *Capacity commitment mechanism for system security and reliability services* rule change request) proposes to introduce an ex-ante, day ahead capacity commitment mechanism and payment to provide access to operational reserve and other required system security or reliability services.

These models could each be used by themselves, together in a hybrid framework, or alongside another mechanism — such as an access standard for connection.

QUESTION 14: MECHANISMS FOR SYSTEM STRENGTH ABOVE MINIMUM LEVELS NECESSARY FOR SYSTEM SECURITY

In relation to the provision of system strength above minimum levels necessary for system security and the relevant rule change requests:

1. Do stakeholders consider the centrally coordinated model, as proposed by TransGrid, is the preferable option for providing system strength above the essential levels required for secure operation?
2. Do stakeholders consider the decentralised, market-based model proposed by HydroTasmania is the preferable option for providing system strength above the essential levels required for secure operation?
3. Could a hybrid of these models be used to deliver system strength above the minimum?
4. What do stakeholders perceive to be the strengths and weaknesses of each model?
5. Do stakeholders consider there are other, alternative models for delivering system strength above the minimum levels required for secure operation?
6. What do stakeholders perceive to be the biggest benefits and risks to introducing a mechanism to deliver system strength above the minimum levels required for secure operation?

7 RESERVE SERVICES

This section seeks stakeholder feedback on the need for an explicit operating reserve, ramping or other dedicated reserve service for the NEM. Infigen's *Operating reserve market* rule change request refers to a dynamic operating reserve service that could be sourced from online and off-line resources that can meet the criteria. Delta's *Introduction of ramping services* rule change requests proposes a spinning reserve that can be used as a ramping service. Delta's other rule change request, *Capacity commitment mechanism for system security and reliability services,* refers to operational reserves that would be available to be used if committed one day ahead.

Though the characteristics vary, each proposal speaks to a dedicated in-market reserve service to respond to unexpected changes in supply or demand to keep the power system secure and/or reliable.

7.1 Requirement for a dedicated in-market reserve service, mechanism or market

Reserves are an important part of delivering resource adequacy in any power system.[78] Resource adequacy relates to having a sufficient overall portfolio of energy resources to continuously achieve the real-time balancing of supply and demand. Achieving this balance is an intricate optimisation of available energy resources, both in real time and over longer-term planning time frames.[79] Any undispatched capacity that is made available by market participants in the wholesale market can act as 'in market' reserves and be drawn upon by AEMO as part of various market and regulatory arrangements; however, they are not specifically provided for through a mechanism or market. This is in contrast to 'emergency' reserves which are specifically procured through the RERT.

7.1.1 What are reserves in the NEM context?

A reliable power system has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence. Bulk energy is the core product supplied by the power system to match demand from consumers, at least cost, in line with the reliability standard.[80]

However, to manage uncertainty in the power system, it is necessary to have enough spare capacity to manage the full range of reasonably foreseeable outcomes, across all time frames. This spare capacity is known as "reserves" and includes generating capacity (or demand response) that can be used when required, but is not actively engaged in supplying bulk energy for the relevant time period.[81] There are two main types of reserves in the NEM

78 Reserves are defined in Chapter 10 of the rules

79 Energy resources include centralised generation and DER, demand response, and network capacity.

80 The current reliability standard requires there be sufficient generation and transmission interconnection in a region such that at least 99.998 per cent of forecast total energy demand in a financial year is expected to be supplied.

81 Reserves are defined in Chapter 10 of the rules.

that can be called into use when standard processes to provide bulk energy fail to meet demand. These include:

1. **In-market 'reserves'** - spare capacity available in the system given the amount of generation, forecast demand and demand response, and network capability at any point in time. This capacity could be online and 'spinning' or offline as long as it can be guaranteed to start up before needing to provide a response. Market reserves can be thought of as the "buffer" that is made available by the market as part of the usual operation of the NEM to help manage unplanned system developments, such as the loss of a large generator or a sudden increase in demand. There are no formal processes to procure these at the moment, and this is the subject of these rule changes.
2. **Emergency reserves** - reserves contracted through the Reliability and Emergency Reserve Trader (RERT) provisions in the NER and used by AEMO to respond during times when a shortfall in market reserves is forecast, or where practicable, to maintain power system security.[82] The generation or demand response contracted for emergency reserves are not otherwise available in the market. This has a formal process to procure these, and the RERT has recently been reviewed extensively through the *enhancement to the RERT, Victorian derogation - RERT contracting* rule change requests, as well as the ESB's out of market mechanism.

Operating reserves, ramping services and other in-market reserves referred to Infigen and Delta's rule change requests, all refer to specific amounts of in-market reserves that would be identified as necessary to fill a specific power system need. The proposals indicate that the amount needed would be set ahead of time, arrangements would be in place to procure and pay for these so they can be made available for AEMO to use in response to unexpected changes in supply or demand.

7.1.2 Reserves under the current NEM regulatory framework.

At present, the NEM does not include an explicit operating reserve or ramping service, nor a mechanism or market to explicitly value, procure and pay for reserves. Instead, market participants may make a commercial decision to maintain spare capacity within their portfolios to ensure they can meet their commercial obligations. This spare capacity can be used as reserves when mobilised by market participants perhaps in response to high prices, or calls from the operator for additional reserves.

While commercial drivers are a key reason participants invest in spare capacity to begin with, the question of whether or not participants make this capacity available to be called upon as reserves at a specific point in time, is driven by an escalating series of market and regulatory incentives that make up the NEM's reliability framework.[83] The reliability framework as a whole aims to deliver enough power supply and demand response to satisfy the reliability standard through market mechanisms to the greatest extent possible.[84]

82 Under Clause 3.20.3(b) of the NER, AEMO may dispatch RERT reserves if practicable to do so, only in circumstances where AEMO has already procured RERT services for reliability purposes and these resources could help with a power system security issue.

83 For more information see AEMC's *Reliability frameworks review,* 26 July 2018, chapter 2.

84 AEMO uses the Reliability Standard as the primary criterion to evaluate whether the power system has sufficient supply resources to meet future consumer demand. AEMO operationalises the reliability standard through its forecasting processes, which are

For example spot and contract prices tend to increase in times of expected or actual scarcity, and participants can make spare capacity available at these times in the hope of reward if their capacity is called upon. If a shortfall is identified, AEMO informs the market of a 'lack of reserve' (LOR) condition to encourage a response from market participants to provide more capacity into the market. Generators may offer in more supply, or consumers can reduce their demand, and be rewarded if this capacity is called upon. In these situations, market responses can potentially have the effect of improving market reserve margins, and maintaining power system reliability. However, in the absence of an explicit reserve service it may be hard to tell whether this is the case. Some of this is reflected in the various materials produced through the Projected Assessment of System Adequacy (PASA) processes.

If the market does not make spare capacity available when needed, AEMO has the power to intervene using emergency RERT reserves, directions to generators or loads or, as a last resort, controlled load shedding to deliver a reliable and secure power system.

Delta — in its *Introduction of ramping services* and its *Capacity commitment mechanism* rule change requests and Infigen — in its *Operating reserve market* rule change request suggest that the current market and regulatory incentives to offer spare capacity that can be drawn upon by AEMO as market reserves during times of need (e.g. when a lack of reserve is signalled) are insufficient to warrant market participants to make this capacity available, especially given these periods are often brief, increasingly unpredictable and the reward for participants during these times does not necessarily eventuate and when it does, it may not reflect the value or the cost of providing reserves at that moment.[85]

The market requires reserve capacity at times, but does not explicitly value it. A new mechanism or market could be introduced to explicitly identify, procure and pay for a certain level and type of reserve to be made available to AEMO to manage uncertainties in the NEM.

7.1.3 The changing need for reserves in the NEM

The NEM has always needed reserves in order to supply customers with the energy that they demand with a very high degree of confidence.

However, the **potential need for reserves is increasing.** Some factors contributing to this increasing need for reserves include:

- increasing variability and uncertainty on both the supply and demand side leading to increasing uncertainty and variability in the system's ability to cover system needs under an existing framework that is based on self-commitment by market participants in real/near to real time
- a new and a dramatically wider range of power system 'modes of failure' that are driven by both external factors like extreme weather and climate change, as well as internal factors like integration of new technologies into the power system.

updated almost continuously to show expected levels of unserved energy based on new information, including information about generation availability (e.g. whether a generator is out on maintenance or not) and changing weather conditions. The forecasting process seeks to inform market participant' and AEMO' decisions with the latest and most accurate information available.

85 Participants are only paid if capacity is dispatched. Capacity that is made available to be drawn upon as reserves, but not used, received no reward.

- gaps in our understanding of how new "failures" may play out and therefore how the operator and participants could or should prepare, withstand and respond to these.

At the same time, **it is thought that the amount of reserves in the NEM is decreasing**[86]

Market participants have traditionally held some spare capacity either to support the technical operation of their plant, or to meet commercial obligations that incentivise them to be available at particular times. If offered in the market, the aggregate amount of spare capacity that is not dispatched for an interval can be considered to be "reserves" that can be called upon to respond to unexpected changes in supply or demand. In its rule change request, Infigen suggests that these participants are starting to exit or withdraw capacity from the market for financial, physical or other commercial reasons.[87]

Many of the new participants entering the market operate under business models with commercial incentives and penalties structured around total megawatt output at *any* time rather than at a particular time of need. Some have different physical characteristics that limit the amount of reserves they can guarantee to the market.

Even if there is less or no need to include reserves in a commercial portfolio to fulfil commercial obligations, participants may look to invest in reserves if market incentives are strong. Infigen and Delta have indicated in their rule change requests that current market and regulatory incentives to invest in, or make reserves available to the market are not sufficient for a number of key reasons:

- The potential high-price reward for making reserves available does not always eventuate. Even when it does, the market price cap may not be enough to compensate a participant for the costs of making those reserves available. While this has always been a risk, in the past participants sought to recover any shortfall in revenue during other moderate price intervals. Recent years have seen the entry of large amounts of renewable energy receiving revenue outside the market. This has led to an increasing number of low and negative price intervals, reducing the opportunity for participants to recover the additional revenue at other times.
- As the generation mix transitions from a small number of large, predictable generators, towards a large number of smaller, variable generators, unexpected changes in supply and demand are increasingly difficult to predict. With this comes increasing difficulty in predicting the *amount* of reserves that may be needed to respond to a change and the *time* at which the reserves might need to be made available. Participants suggest the potential risks of investing in reserves outweigh the potential benefits in the current and future NEM.
- Price signals that should indicate a need or at least an opportunity for investment in technologies that provide reserves, are being blunted by government actions. Over the years this includes direct investment in generation assets, support for specific generation technologies, and pressure on market participants to set aside commercial interests to

86 Infigen Energy, *Operating reserve markets* electricity rule change proposal, 19 March 2020, p.1.

87 Infigen Energy, *Operating reserve markets* — Electricity rule change proposal, 19 March 2020, p.3.

focus on social outcomes. Infigen sights "random and capricious government interventions" as a key deterrent to investing in privately owned reserves.[88]

These factors may lead to a situation in which participants can see a need for reserves and a commercial opportunity to invest in technologies or equipment that can provide them, but find it difficult to get finance to support the investment.

7.1.4 Considering the nature of the requirement for an explicit reserves mechanism, market or arrangement

Setting aside the increasing need for and decreasing amounts of reserves in today's NEM, and the potentially insufficient incentives to invest in new reserve capacity, an explicit arrangement to define and procure reserves would require the consideration of a number of factors.

- Explicit arrangements to procure reserves will likely involve a new payment for a service that has always existed in the NEM. Alternatively, it could be argued that a new payment for in-market reserves is simply providing a fair value for a necessary service that has been provided for free, or below cost until now.
- The objective that an explicit in-market reserve mechanism or market is trying to meet would dictate the characteristics that the reserves would need to display. Would peak megawatts alone be sufficient to respond to the uncertainties presenting themselves in the NEM now and in the future? Or is responsiveness or the ability to guarantee reserves ahead of time important?
- Explicit in-market reserves may reduce the need for and use of RERT, directions and ultimately load shedding.
- Paying for in-market reserves may better reflect participant costs of providing those reserves at the particular point in time. This would provide greater incentives for the provision of reserves.
- Explicit arrangements to procure in-market reserves will inevitably compete with spot, contract and FCAS markets. It may also impact the amount of reserves available for RERT and/or offering into future demand response markets or mechanisms. Consideration will need to be given to whether and how incentives can be balanced and/or reserves can be co-optimised to meet customer and power system needs at the lowest cost.
- Like with many system services, the rewards that could be captured by any individual participant for providing the service are lower than the costs to the system and consumers of not having enough of the service. Explicitly defining the service may allow for this trade-off to be evaluated more transparently.

These matters will be explored with stakeholders to establish whether or not there is a need for, and if so, how best to design an explicit in-market reserve mechanism or market that delivers benefits to consumers efficiently.

88 Infigen Energy Limited, *Operating reserve market* — Electricity rule change proposal, 19 March 2020, p.4.

7.1.5 Relevant rule change requests

In its rule change request, Infigen suggests the amount of reserves available is decreasing given the changing generation mix. Infigen suggests the incentives to invest in resources that have operating reserve capability are not sufficient given the uncertain rewards available to participants for making these reserves available. Infigen proposes the introduction of an operating reserves market that would set and value operating reserves dynamically to reflect the true cost of scarcity. [89]

Delta has submitted two rule change requests which seek to address the emerging gap in available reserves. In the *Capacity commitment mechanism for system security and reliability services* rule change request, Delta proposes the introduction of an ex-ante day-ahead commitment mechanism and payment that would compensate eligible plant to operate at minimum safe operating levels so that they remain available for AEMO to draw upon if needed to respond to unexpected changes in supply or demand.[90] In the *Introduction of ramping services* rule change request, Delta proposes the introduction of new raise and lower ramping reserve services which would be procured in a similar way to current arrangements for FCAS but would operate over a longer 30-minute time frame.[91]

QUESTION 15: REQUIREMENT FOR AN EXPLICIT IN-MARKET RESERVE MECHANISM OR MARKET IN THE NEM

1. What do stakeholders see as the key drivers or changes in the NEM that could be addressed by introducing an explicit in-market reserve arrangement?
2. Do stakeholders' think there is a need for an explicit in-market reserve arrangement in the NEM. If yes, do stakeholders consider the need to be permanent or transitional?
3. How would an explicit in-market reserve mechanism or market impact stakeholders? What would be the key benefits and costs? Would it effect stakeholders' operational or investment decisions?
4. Do stakeholders' think there to be an explicit need for a capacity commitment mechanism as proposed by Delta? Do stakeholders' think this as a separate need to an in-market reserve service?

7.2 Achieving security and reliability using dedicated in-market reserves

A secure power system is one 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. A reliable power system has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence.

89 Ibid.

90 Delta Electricity, *Capacity commitment mechanism for system security and reliability services* — Electricity rule change proposal, 4 June 2020,p.10.

91 Delta Electricity, *Introduction of ramping services* — Electricity rule change proposal, 4 June 2020, p.7.

A reliable power system will also be a secure power system. However, the converse is not necessarily true; a power system can be secure even when it is not reliable.

The two concepts are closely related operationally and it is not always simple to separate them. For consumers, the final result of either a reliability event or a security event may be indistinguishable. However, it is important to understand how these two aspects of power supply work if additional tools or mechanisms are proposed to improve one, the other, or both. The concept of reserve services are where these two concepts come together.

This section will explore whether new arrangements to explicitly define and procure dedicated in-market reserves are proposed to manage security (technical matters), reliability (enough capacity) or both. The end of this section describes briefly how the reserve services proposed by Delta and Infigen would deliver both reliability and security outcomes depending on specific design choices.

7.2.1 The security and reliability consequences of not having enough reserves

The objectives of an in-market reserve mechanism or market can be derived from what the outcome would be in the absence of having sufficient reserves under different system conditions.

From a reliability perspective, a lack of sufficient reserves may result in some limited load shedding. In the current market arrangements, AEMO may look to avoid load shedding through the activation of RERT or by intervening in the operation of the market through directions.

From a security perspective, a lack of sufficient reserves may compromise the ability of AEMO to return the system to a secure operating state following a contingency event. Under current market arrangements, AEMO must return the power system to a secure operating state within 30 minutes of a contingency event occurring such that there are sufficient reserves for the market to withstand a further credible contingency event.

The role of reserves in response to both security and reliability events is important, but the temporal aspect — the fact that reserves are drawn upon *following* a security event, but likely *before* a reliability event — indicates that the value of reserves in preparing for and withstanding reliability events are perhaps a stronger driver in making the case for an explicit in-market reserve mechanism or market in the NEM.

In either case, dedicated in-market reserves should be considered in the context of the broader frameworks that currently exist to deliver reliability and security, and those that may be proposed through other reforms currently under way, such as the ESB's post-2025 work.

For example, current NEM reliability frameworks include a hierarchy of market signals, information and regulatory tools and interventions to identify, prepare for and respond to reliability issues. This includes the reliability standards and settings as well as the retailer reliability obligation to name a few.

The existing security framework is also equipped with a multi-layered set of signals, information processes and supporting mechanisms to deliver a power system where equipment operates within its allowable ratings, the power system as a whole is maintained in a stable condition, within defined technical limits, and the power system can be returned to operate within normal conditions following a disturbance.

An explicit in-market reserve mechanism or market would need to complement rather than cut across these existing processes and mechanisms to deliver a service that is both necessary and additional to what already exists.

Understanding whether the primary objective of operating reserves, ramping services or other in-market reserve services is to address the security or reliability needs of consumers and the power system will underpin the policy design choices — like aheadness, eligible plant characteristics, trigger, minimum requirement — for any new operating reserve arrangement. We are interested in stakeholder views on this point.

7.2.2 Relevant rule change requests

Both the Infigen *Operating reserve market* rule change request and the two Delta rule change requests refer to their proposals as meeting a reliability need ("enough megawatts available when you need them"). However, the rule change requests also reference the fact that other system services such as inertia, system strength and ramping services could be provided by resources that were made available as part of a new in-market reserve market or mechanism.

QUESTION 16: ACHIEVING SECURITY OR RELIABILITY OUTCOMES USING A NEW IN-MARKET RESERVE MARKET OR MECHANISM?

1. Do stakeholders have views on whether an in-market reserve market or mechanism should solve primarily for reliability outcomes and security outcomes second? Or can this be more effectively co-optimised?
2. How do stakeholders' think an explicit in-market reserve market or mechanism interacting with the existing NEM reliability framework? What are the policy design priorities for a new operating reserves arrangement that would deliver the reliability needs of the power system?
3. How do stakeholders' think an explicit in-market reserve market or mechanism interacting with the existing NEM security framework? What are the policy design priorities for a new in-market reserve market or mechanism that would deliver the security needs of the power system?

8 FREQUENCY CONTROL

This chapter explores a number of issues and potential reforms to the arrangements under the NER that relate to the control of power system frequency.

8.1 Synchronous inertia

This section discusses potential reforms to the arrangements in the NER for synchronous inertia.[92]

Power systems with large numbers of online synchronous generators have higher levels of system inertia.[93] Renewable generators that are connected to the grid through inverters do not synchronously connect to the grid and do not provide inertia. However, many inverter-connected technologies have the capability to deliver fast frequency response (FFR). FFR generally refers to the delivery of a rapid active power increase or decrease by generation (or load) in a time frame of two seconds or less, to correct a supply-demand imbalance and assist in managing power system frequency.[94] At low levels of inertia, FFR can assist with frequency management.

Declining levels of inertia

A key issue in respect of the provision of inertial response in the NEM relates to the growing number of non-synchronous generators connecting to the grid. This has resulted in the displacement of online synchronous generators and, as a consequence, a reduction in the availability of inertial response in many parts of the network.

Stage 1 of the AEMO RIS report forecasts increased levels of non-synchronous generation to come online and projects current levels of inertia to decline further out to 2025. This would result in the power system operating in a configuration where the system dynamics are very different to those experienced today. For example, the volume and/or speed of frequency sensitive reserve following a contingency event needed would need to be increased.[95] Under the projected condition, AEMO considers more and/or faster frequency sensitive reserve will be needed.[96]

The behaviour of inverter based generation systems has made the power system more complex and can exacerbate post contingent outcomes for credible and non-credible contingency events.

The appropriate time frames for the provision of synchronous inertia as a system service will be considered, including the role of planning arrangements and the potential role of unit-

92 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.

93 For a more detailed description of the role of inertia in power system frequency control refer to section 2.3 of the AEMC's *Frequency control frameworks review* - Issues paper, 7 November 2017, pp.12-13.

94 AEMO, *Fast Frequency Response in the NEM*, working paper, August 2017.

95 AEMO, *Renewable integration study: Stage 1 Report*, p. 63, April 2020

96 Ibid. p.44.

commitment and ahead market arrangements. These concepts are explored further in section 9.1 and section 9.2.

Relevant rule change requests

The relevant rule change requests that raise issues related to the provision of synchronous inertia include:

- Delta Electricity — *Capacity commitment mechanism for system security and reliability services*
- Hydro Tasmania — *Synchronous services markets*
- TransGrid — *Efficient management of system strength on the power system*

Each of these rule change requests raises issues related to the arrangements for the efficient provision of inertia to meet system requirements, including the proposal for new mechanisms to directly compensate or reward market participants that provide synchronous services such as synchronous inertia.

In its rule change request, *Capacity commitment mechanism for system security and reliability services,* Delta proposes the introduction of a day-ahead capacity commitment schedule and payment to keep synchronous plant operating and online. This arrangement is intended to provide operating reserve capacity along with synchronous services such as inertia and system strength.

Hydro Tasmania proposes, in its rule change request, to address the shortage of "inertia and related services in the NEM" by integrating the dispatch of a "synchronous service" with the existing energy and FCAS spot markets. The rule change request presents a solution enabled through changing the formulation of the constraints that are applied to the NEM dispatch engine (NEMDE). These reformulated constraints allow the dispatch engine to find the lowest overall cost combination of synchronous services and non-synchronous generation, to deliver the lowest overall costs for consumers.

Under the NER, TNSPs are obligated to provide minimum levels of inertia once a shortfall is declared by AEMO, similar to the arrangements for the minimum levels of system strength. The TransGrid rule change request notes that any changes to the system strength minimum level framework would require consideration of how this would affect the minimum inertia frameworks. It is also noted that these frameworks are currently not explicitly linked leading to inefficiencies in their operation, and that this should be considered throughout this rule change process. The rule change proposal includes changing the minimum inertia framework to reflect changes in the minimum system strength framework to avoid opportunity costs – such as the efficiencies from coordinating the procurement of related system services, like inertia and voltage control.

Infigen's rule change request, *Fast frequency response market ancillary service*, also raises the issue of managing the power system with reduced synchronous inertia and increased RoCoF. In the case of this rule change request the proposed solution is the introduction of new market ancillary services for fast frequency response similar to the existing FCAS markets. Previous work by the AEMC has shown that greater amounts of FFR, or faster acting FFR services, can reduce the amount of inertia required to maintain system frequency within the bounds of the FOS. Consequently, co-optimisation of inertia and FFR is likely to lower the cost of managing system RoCoF.[97]

QUESTION 17: REFORMS RELATED TO THE PROVISION OF SYNCHRONOUS INERTIA

1. Do stakeholders consider that the issues relating to declining levels of synchronous inertia have been adequately and accurately described?
2. Are there any other issues related to the provision of synchronous inertia that have not been adequately described?
3. What are stakeholders views on the approach to considering the interaction between FFR and inertia in the NEM?

8.2 Frequency control services for normal operating conditions

The AEMC has undertaken a substantial amount of work over recent years in relation to the arrangements for frequency control during normal operation. A summary of this work is set out in appendix a.3. The Commission considered this issue in detail through the 2018 *Frequency control frameworks review* and recommended that:[98]

> In the long term, market participants should be incentivised to provide a sufficient quantity of primary regulating services to support good frequency performance during normal operation.

Through the *Frequency control frameworks review*, the Commission developed a frequency control work plan in collaboration with the other market bodies. The frequency control work plan included provision for interim arrangements to be put in place to improve frequency control in the NEM.

On 26 March 2020, the Commission made a final rule, *National Electricity Amendment (Mandatory primary frequency response) Rule 2020*, in response to a rule change request submitted by AEMO on 16 August 2019. This rule addressed an immediate need identified by AEMO to improve frequency control in the NEM during normal operation and following contingency events. The substantive elements of the rule took effect on 4 June 2020 and sunset after 3 years on 4 June 2023. In its final determination, the Commission noted that a mandatory requirement for PFR on its own is not a complete solution and may not be sufficient to meet the operational needs of the power system now and in the future. The Commission considered that it would be preferable to introduce alternative or complementary arrangements that incentivise and reward the provision of frequency control in the NEM. To inform the development of such arrangements, the Commission considered that further work

97 AEMC, *Managing the rate of change of power system frequency — Final determination*, 19 September 2017, p.58.

98 AEMC, *Frequency control frameworks review* — Final report, 26 July 2018, p.viii.

needs to be done to understand the power system requirements for maintaining good frequency control.[99]

The Commission committed to investigate the appropriateness of the existing incentives for PFR during normal operation and amend these arrangements as required to meet the future needs of the power system. The areas of focus for reform of the arrangements for frequency control during normal operation include:

- the arrangements for allocation of costs associated with regulation services — 'causer-pays'
- the potential development of additional complementary measures to effectively remunerate providers of primary frequency response
- interaction with the Mandatory primary frequency response rule including the sunset arrangements.[100]

In relation to the 'causer pays' arrangements, through the *Frequency control framework review*, the AEMC identified the following areas for potential improvement to the way that regulation FCAS costs are recovered:

- a temporal disconnect between a market participant's contribution to the need for regulation FCAS and the costs charged to that market participant
- a lack of transparency and simplicity in the calculation of market participants' costs
- charges for contributing to frequency deviations are not balanced through crediting or valuation of positive contribution factors.

Appendix C.1 includes further detail on each of these issues along with a summary of the outcomes from AEMO's most recent determination of the *Regulation FCAS Contribution Factor Procedure,* which concluded in November 2018*.*

Relevant rule change request

The rule change request that relates to the arrangements for frequency control during normal operation is AEMO's rule change request *Primary frequency response incentive arrangements*. The Commission initiated consultation on this rule change request on 19 September 2019 under the name: *Removal of disincentives to primary frequency response*. The AEMC has renamed this rule change project to more accurately reflect the scope and objectives for this rule change request in the context of the other rule change requests discussed in this consultation paper.

QUESTION 18: REFORMS RELATED FREQUENCY CONTROL DURING NORMAL OPERATION

1. Do stakeholders consider that the issues relating to frequency control during normal operation have been adequately and accurately described?

99 AEMC, *Mandatory primary frequency response — final determination*, 26 March 2020, p.24.

100 The substantive parts of the *Mandatory primary frequency response* rule will sunset on 4 June 2023.

2. Are there any other issues related to frequency control during normal operation that have not been adequately described?
3. What are stakeholder views on the proposed approach to reforming the process for the allocation of the costs of regulation services (Causer pays)?
4. Is the level of specification of regulations services in the NER fit for purpose as the power system transforms?

8.3 Frequency control services for managing contingency events

The process of technological change in the power system is driving a reduction in the levels of synchronous inertia and an increase in the uncertainty and complexity in relation to maintaining the system in a secure operating state following contingency events.[101] In the context of this change AEMO considers that there is a potential emerging need for more and/or faster frequency sensitive reserve to ensure the frequency operating standard (FOS) continues to be met for all credible events.[102]

This section describes potential reforms to the arrangements for frequency control services to manage power system frequency following contingency events. This includes frequency responsive reserves provided through the ancillary service market arrangements for contingency FCAS, and any non-market frequency response, including mandatory primary frequency response in accordance with clause 4.4.2(c1) of the NER.[103]

The Commission's assessment of the *Fast frequency response ancillary service market* rule change request will build on the findings from the Commissions 2018 *Frequency control frameworks review* and be informed by the recommendations from AEMO's *stage 1 Renewable integration study report*. The relevant aspects of each of these previous pieces of work are discussed below.

Findings from the AEMC's 2018 Frequency control frameworks review

Through the 2018 *Frequency control frameworks review,* the Commission investigated the effectiveness of the frequency control frameworks in efficiently providing frequency control services to manage the risks of contingency events.

The Commission concluded that the current frequency control frameworks:[104]

- do not place an explicit value on the provision of fast frequency response (FFR) services or inertia, and do not coordinate with the provision of other system services, such as system strength

101 AEMO, *Renewable integration study: Stage 1 Report*, April 2020, p.10.

102 Ibid, p. 45.

103 The *Mandatory primary frequency response rule 2020* introduced changes to the NER to require that all scheduled and semi-scheduled generators which have received a dispatch instruction to generate to a volume greater than zero MW must operate their generating system in accordance with the Primary Frequency Response Requirements as applicable to that generating system. This requirement takes effect on 4 June 2020 and will sunset on 4 June 2023.

104 AEMC, *Frequency control frameworks review* — Final report, 26 July 2018, pp.78 – 80.

- reflect a 'traditional' generation mix and therefore may not adequately support new technologies and the services needed as the power system changes
- may not provide longer-term investment certainty due to a lack of counterparties willing to hedge FCAS market risks
- do not provide incentives for market participants to reduce their potential impact on the need for frequency control services.

The Commission also found that the specification of the contingency services by AEMO in the Market ancillary services specification (MASS) may be inefficiently limiting participation in the FCAS markets by newer technologies and undervaluing their response capabilities. The final report included the following recommendations in relation to the MASS:[105]

> That AEMO:
>
> 1. undertake trials of distributed energy resources providing FCAS, including virtual power plants, that consider various technology types and different options for metering and verification, with a view to sharing the outcomes of the trials with relevant stakeholders and incorporating the outcomes of the trials (and any other trials of new technologies providing FCAS) into a review of the MASS.
> 2. conduct a broader review of the MASS that seeks to address any unnecessary barriers to new entrants, or any aspects of the MASS that may not appropriately value services provided by newer technologies where these services are valuable to maintaining power system frequency. This should include consideration of:
>   a. the timing specifications for each of the different FCAS
>   b. the overlapping interactions between the different FCAS specifications.
>   c. any changes that may be necessary to settings within the MASS
>   d. issues raised in the most recent review of the MASS that were considered out of scope.

Relevant recommendations from AEMO's stage 1 Renewable integration study report

AEMO's Renewable integration study stage 1 report, identified a number of challenges in relation to frequency control in the NEM and made a series of recommendations for further action.

The key challenges identified by AEMO were:[106]

- A lack of consistency and certainty of PFR delivery from generation.
- An expected reduction in minimum levels of online synchronous inertia of 35% by 2025.
- Increased operational complexity associated with the behaviour of distributed PV, inverter-based resources and generation run-back schemes.

105 AEMC, *Frequency control frameworks review* — Final report, 26 July 2018, p.xi.

106 AEMO, *Renewable integration study: Stage 1 Report*, p. 10, April 2020

In the context of these challenges AEMO recommended the development of a frequency control work plan with a number of action items including to:[107]

- Revise ancillary service arrangements to ensure the required speed and volume of PFR match the size of the Largest Credible Risk (LCR) and Frequency Operating Standard (FOS) containment requirements for the range of expected future operating conditions.

The Commission will continue to work with ESB, AEMO and the AER in relation to the arrangements in the NER that relate to the management of the power system frequency following contingency events.

Relevant rule change requests

The rule change request that relates to the arrangements for frequency control following contingency events is Infigen's rule change request *Fast frequency response market ancillary service*. In this rule change request, Infigen proposes that the NER be changed to introduce two new market ancillary services to respond to frequency disturbances following contingency events, one for raise FFR and another for lower FFR.

QUESTION 19: REFORMS RELATED FREQUENCY CONTROL FOLLOWING CONTINGENCY EVENTS

1. Do stakeholders consider that the issues relating to frequency control following contingency events have been adequately and accurately described?
2. Are there any other issues related to frequency control following contingency events that have not been adequately described?
3. What are stakeholders views on the best way to address the challenges to managing system frequency following contingency events, including reforms to value and reward FFR?
4. Is the level of specification for contingency services in the NER fit for purpose as the power system transforms?

107 Ibid.

9 INTERACTIONS BETWEEN SYSTEM SERVICES

This chapter explores interactions between the issues raised in the rule change requests and how these interactions may be considered in the development of policy mechanisms to support the provision of system services.

9.1 Technological and temporal issues related to system service provision

Market and regulatory arrangements for the provision of system services should be coordinated across investment, commitment and dispatch time frames to maintain system security and minimise the overall cost of system operation. This requires consideration of the technological aspects of service provision, to understand how different combinations of services may be provided by different technologies. It also requires consideration of how services may be provided over time, to understand how services may interact and complement each other over different time frames.

9.1.1 Technological considerations

Different technologies have different characteristics and capabilities in relation to the provision of system services. Some technologies may have the capability, or may be designed specifically, to provide only one, or a particular subset of services. Other technologies may inherently provide multiple system services at the same time, as a consequence of operation. This may occur as a "by-product" when they provide energy, or another system service.[108] Other technologies may have the capability to provide multiple services on an optional basis during operation.

Conventional synchronous generators provide most system services inherently as a consequence of online operation. For example, synchronous generators can provide physical inertia, reactive power control and system strength as by-products (either automatically and intrinsically, as is the case for inertia and system strength, or through relatively minor adjustments of controls, as is the case for reactive support provided through adjustment of automatic voltage regulators), whenever they provide energy or frequency response.

In contrast, non-synchronous generators generally do not automatically provide the same kinds of synchronous services, as a by-product of generating energy. However, while non-synchronous generation may not inherently provide the same system services as a by-product, there are many new technological capabilities that can be utilised to enable them to provide system services. These capabilities may be described as 'add-ons' that can be provided, if required by regulatory obligations or in response to market incentives.[109]

108 It is important to note that the application of the term "by-product" to a given service does not always imply the by-product has no value. The term more reflects the fact that the by-product was not originally intended to be the main product of the relevant asset, or for which that asset was optimised to produce. For example, synchronous generators were historically optimised to produce energy, with inertia produced as an unintentional (but valuable) by-product.

109 For example, non-synchronous generating units can provide reactive support, through particular adjustments to settings of control equipment, or through installation of reactive control plant. Similarly, non-synchronous generators can provide system strength services, through installation of synchronous condensers.

AEMO provided a snapshot of the technological capability of power system equipment in its 2018 power system requirements reference paper where it noted:[110]

> Efficient policy frameworks will take a portfolio approach to sourcing system services, making optimal use of the capabilities of all assets in the power system, which, when used in combination, should be capable of providing the same or better system performance than in the past.

The capability of power system equipment continues to evolve over time. For example, existing non-synchronous inverter technologies ("grid following" inverters) do not provide significant voltage wave form stabilisation, and so do not provide the same kind of system strength support as a traditional synchronous generator. However, as technologies evolve, it is possible that virtual synchronous machines ("grid forming" inverters) will be able to set a reference voltage, and therefore provide the system strength that stabilises voltage wave forms. Other types of technology that produce a similar effect may also emerge.

The changing nature of power system technology is changing what is possible in relation to provision of system services, which were once only provided inherently, as a by-product of operating a synchronous generator. The development of market and regulatory arrangements for the adequate and efficient provision of these services must be open to the provision of system services from new sources. Such arrangements are able to adapt to future technological advances to efficiently meet the operational needs of the power system over time, at the lowest possible cost to consumers.

9.1.2 Temporal considerations for optimal provision of system services

As set out in Chapter 3, the provision of system services is considered across a range of time frames, described as the *investment*, *commitment* and *dispatch* time frames. In relation to each system service, it needs to be considered over which time frame, or set of time frames, the service can be provided. It will also be necessary to consider the interaction of arrangements for the provision of different services within the same time frames and across multiple time frames.

An important consideration is the extent to which the procurement of services within an earlier time frame increases confidence in service availability and reduces overall costs, as opposed to procurement of the same or similar services in later time frames. There are risks associated with making decision over each time frame, and the relative magnitude of each risk needs to be considered when developing regulatory frameworks.

Decisions made at a point in time impact future options

A decision made at one point in time has implications for the options that are available for selection as part of a later decision process. In relation to system services, decisions made in an investment time frame will impact the options available for selection closer to real time, through the processes of unit commitment and dispatch. Similarly, the outcomes from an

110 AEMO, *Power system requirements*, March 2018, p.20.

ahead market or unit-commitment mechanism will impact the options available for dispatch arrangements.

One benefit of making decisions in advance, or across longer time frames, is a reduction in the risk of a system security problem arising. For example, a minimum inertia requirement that drives investment in assets to provide inertia over a longer time frame, may reduce the risk of there being insufficient synchronous inertia in the power system for secure operation. This supports the security of the power system and therefore provides a stable foundation for the operation of the electricity market.

However, there are also costs of applying such arrangements. These are related to:

1. the bringing forward of the costs of building the assets to provide the service, and
2. the risk that the issues the services were build / procured to address, do not eventuate.

This creates a risk of higher than necessary costs incurred, through potential over provision of a service. It may also remove any dynamic price signal for the provision of a similar, substitutable service, that may have been called on over an operational time frames and which may have been able to meet the system security requirements at a lower cost.

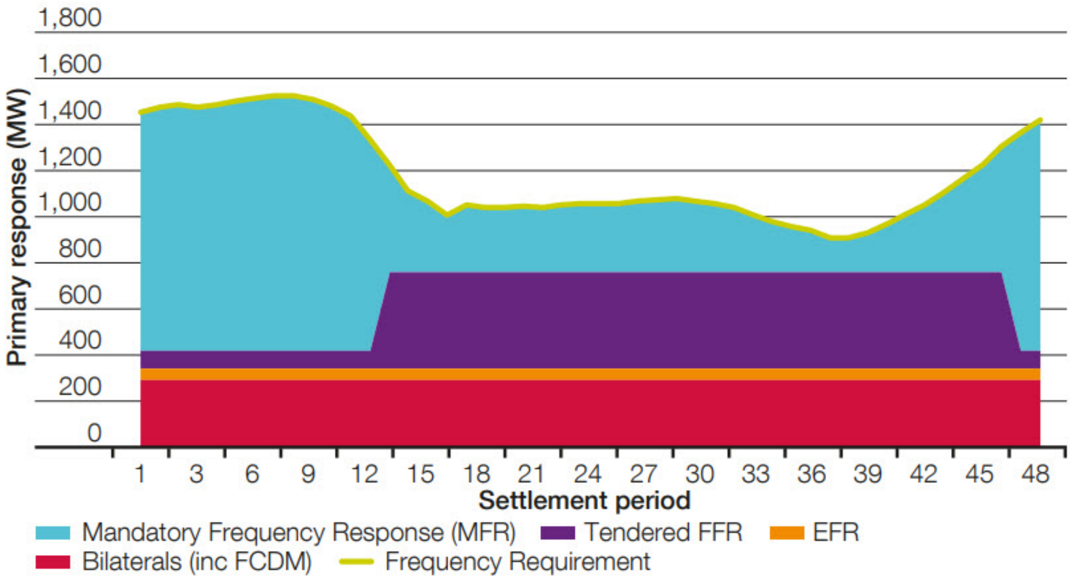
In considering the risks of making decisions in advance or closer to real time, its necessary to assess the relative magnitude of each risk. On the one hand, the risk of making decisions ahead of time is that assets are stranded or underutilised, driving higher costs for consumers. On the other, the risk of making decisions closer to real time is that insufficient services are available when needed, driving system security shortfalls and potentially resulting in curtailment of customer load. It follows that in assessing new frameworks for the provision of system services, these relative risk magnitudes need to be examined and, to the extent practicable, quantified.

Further to this, given the importance of maintaining the secure operation of the power system and the associated uncertainty and complexity, it is likely that some mix or portfolio of policy mechanisms will deliver effective and efficient outcomes. An example of an approach which operates over different time frames is the layered approach to provision of frequency balancing services adopted by UK National Grid, as shown below in Figure 9.1. In this case the system requirement for balancing services to control system frequency is satisfied through contributions from a range of different services including:[111]

- relatively static volumes of reserves from bilateral contracts and EFR (Enhanced frequency response)
- a volume of FFR (Firm frequency response) that varies on a medium term periodic basis
- a dynamic volume of MFR(Mandatory frequency response) that responds to system requirements in real time.

111 An overview of the arrangements for frequency control services used in the UK national grid is available in Appendix G of the AEMC's *Frequency control frameworks review* — Draft report, 20 March 2018. Further information of the ongoing reform of system service arrangements in the UK National Grid is included in Appendix E of this Consultation paper.

Figure 9.1: **UK national grid — Stacking of frequency reserves**



Source: UK National Grid, *Product roadmap for frequency response and reserve*, December 2017, p.13.
Note: This chart illustrates how a portfolio of fixed and flexible services can combine to meet power system requirements

Coordination of policy mechanisms to achieve optimal provision of services

As stated previously, the secure operation of the power system requires the provision of a range of system services to maintain technical specifications such as voltage and frequency within required parameters. In developing new or refined arrangements for the provision of system services, it is necessary to consider the degree to which the provision of different system services can be optimised to reduce the overall cost of operating the power system.

The objective of central dispatch process is to maximise the value of trade in the NEM. This is achieved by dispatching the optimal configuration of energy service providers to meet consumer demand, subject to the operational needs of the power system. A lowest cost outcome for consumers can be achieved where the needs of the power system are met through the co-optimal provision of system services.

There are limitations on the process of dynamically optimising the enablement and provision of system services. For example, the provision of one service can only be co-optimised with that of another where they are considered for commitment at the same time. The decisions that are made closer to real time must then build on those decisions that were made in the past.

In the event that system services are provided across different time frames, the system services framework should allow for periodic feedback to identify opportunities for improvements and support more efficient outcomes over time. Reporting of market and system and performance can improve transparency of these arrangements and provides information to market participants to guide more efficient operational and investment decisions.

> QUESTION 20: TECHNOLOGICAL AND TEMPORAL ISSUES FOR SYSTEM SERVICE PROVISION
>
> 1. What are stakeholders' views on how the arrangements for system services can be developed, to best utilise the capability of both established as well as new and emerging technologies?
> 2. Do stakeholders have any initial thoughts on how the arrangements for system services can be best coordinated over dispatch, commitment and investment time frames?

9.2 Aheadness and commitment

The common objective of the rule change requests discussed in this paper is to make sure the provision of key system services, that are no longer available at the same level or in the same way as they were in the past, are replaced or made available through different arrangements to support a secure power system. Valuing these specific services will encourage potential suppliers to provide these services in the NEM, both over operational and investment time frames, to meet power system needs.

The ESB's post-2025 project has a major time frame to ensure that the power system continues to have the technical properties essential for power system security and reliability of supply available when needed, and that these are provided in an efficient way. As some of these essential technical properties were previously provided as by-products of energy production, they are not all explicitly valued. The ESB's work stream is designed to support efficient investment and provision of these capabilities at the operational time frame (from existing and new sources), mitigating the risks of potential supply shortages or costly interventions.

As the ESB notes, one of the key components to delivering the right mix of resources in real-time and at lowest costs to consumers may involve incorporating a mechanism in the NEM's pre-dispatch and dispatch process that provides visibility and enables efficient co-optimisation of the diverse set of resources ahead of time. This would seek to make all necessary system services available, without costly and distortionary interventions.

This section explores the concepts of "ahead arrangements", which can be used to deliver these services ahead of the dispatch process, drawing on material prepared by the ESB as part of its 2025 work.

9.2.1 Existing 'aheadness' arrangements

An ahead arrangement, or 'aheadness' refers to regulatory or commercial frameworks that provide suppliers (for example, generators, demand response providers), consumers and the market operator with information in the period leading up to real-time. This signals to suppliers whether or not their service will be required, and gives consumers and the market operator more certainty that the service is likely to be provided to meet the expected power system needs and consumer preferences. Ahead arrangements can provide market participants, both on the demand and supply side, with information to make decisions to commit units ahead of dispatch.

The NEM has many features that provide information signals to the market ahead of real time, with these summarised in appendix d.3.

Ultimately, the level of 'aheadness' afforded to market participants represents a balance of risks allocated accordingly between energy producers and consumers. This seeks to ensure a competitive generation market exists alongside the need to deliver the right service in the right region over the right time frames. The choice to allocate to market participants both the decisions to commit units and the associated risks was a deliberate one when the NEM was established.[112] This was because market participants largely have the right information and financial incentives from the spot and contract market to make these decisions, and to adjust these decisions as market conditions change.

However, as recognised by the ESB, market processes will need to be enhanced to coordinate the scheduling of all resources so that the full needs of the system can be provided in a co-optimised way that minimises the cost of delivery. A form of aheadness is considered essential for improving the visibility and confidence in essential system services.

9.2.2 Aheadness and System Services

In April 2020, the ESB set out four reform options that increase the amount of firming and flexibility in the system. The options range from strengthening the commitment mechanism for reliability and security, to ones that are more extensive but integrate fully with the energy market. Over the coming months, the ESB and market bodies will further develop these designs, evaluating the various options to identify a recommended design by June 2021 to form part of the overall post-2025 market design. The below section draws from material put out in the ESB in April 2020, and relates it to the relevant rule change requests that are the subject of this paper.

There are four rule change requests considered in this consultation paper that raise issues around the procurement of reserves and system services through commitment arrangements ahead of dispatch:

- Hydro Tasmania — *Synchronous services markets* (ERC0290), which implies that generating units would need to commit to be online ahead of dispatch, in order to be able to provide synchronous services, but does not specify how far ahead of real-time this would occur.
- Infigen Energy — *Operating reserves market* (ERC0295) which proposes that operating reserves be committed 30 minutes ahead of real time.

112 Ibid p.38

- Delta Electricity — *Ramping services* (ERC0307), which proposes arrangements for a 30 minute raise and lower "ramping" product to be procured ahead of time in a similar way to existing FCAS products,
- Delta Electricity — *Capacity commitment mechanism for system security and reliability services* (ERC0306), which refers to a day ahead capacity commitment schedule.

Generally, the merit of ahead arrangements across all types of system services can be considered to have three categories of benefit to provide:[113]

- Market participants (both supply and demand side) with more, or better quality, information so that they can incorporate this information into their unit commitment and demand response decisions and bids/offers, therefore increasing the efficiency of outcomes in the NEM wholesale and ancillary services markets, including reliability and security outcomes.
- The system operator with more, or better quality, information so that the system operator can use the information to manage the system in relation to reliability and security outcomes. In particular, the system operator would be able to identify any shortfalls in the availability of critical services, such as inertia and system strength, which could potentially cause major instabilities and collapse of the power system if left un-addressed.
- The system operator and participants with a schedule that can be used to anticipate and make commitment decisions, the intent being to increase the efficiency of outcomes in the NEM wholesale market and the planning of any necessary contingency arrangements, including in relation to reliability and security outcomes.

Ahead arrangements may also enable the dynamic optimisation of system services that would otherwise not be able to be co-optimised with each other. For example, it is currently not possible to dispatch synchronous inertia as part of the 5-minute dispatch. Therefore, it is not possible to co-optimise dispatch of inertia with an FFR service through the existing dispatch arrangements. However, it may be possible to develop ahead arrangements that co-optimise dispatch of inertia and FFR.

Currently, the provision of many system services is considered to provide benefits across the market, where a shortfall in these services could lead to large scale physical disruption in the system. In the event of a shortfall, the system cost could be much larger than the cost suffered by individual market participants who are neither obliged nor incentivised to provide these services.[114]

Further, many system services (frequency control, inertia, system strength) are predominantly provided by synchronous generating units as a by-product of providing energy. These generating units are constrained by ramping and start-up lead time to respond to power system needs. It is possible that in a real-time only market, even with a separate system service markets defined, potential system services providers might not respond if there is uncertainty about whether the service will be needed and what the reward will be.[115]

113 Ibid, p. 71

114 ESB, *System Services and Ahead Market Paper,* April 2020, p.22

115 Ibid, p.22

Another important consideration for the ESB and market bodies will be how possible short-term arrangements that achieve efficient service delivery can be aligned with long-term arrangements that account for the implications of a more distributed and decentralised system service provision capability over time.

QUESTION 21: AHEADNESS AND COMMITMENT

1. Do stakeholders agree with the characterisation of arrangements for aheadness and commitment, including the potential benefits?
2. What are stakeholders' views on the potential downsides of introducing arrangements for commitment of capability ahead of dispatch?
3. Are there alternative arrangements that can reduce the increasing uncertainty associated with power system operation in the NEM?

9.3 Cost recovery arrangements

One of the key considerations in designing new regulatory arrangements is how to recover any costs; in this case the costs associated with the procuring the service as well as the regulatory cost associated with the arrangement itself. This requires an understanding of the costs themselves and who benefits from the outcomes.

The rule change requests discussed in this paper each propose new arrangements for procuring system services. These arrangements may introduce new costs into the system or at least make the true costs of providing a service more transparent. When considering an appropriate model to recover the costs of these services it will be important to understand why the need for the service is arising.

The cost recovery arrangements in the NEM are generally based around the idea that those who cause the need for the service should pay for the costs of the service, asset or activity.

Chapter 3 of the NER sets out the rules governing the operation of the market relating to the wholesale trading of electricity and the provision of market and non-market ancillary services. Clause 3.1.4 sets out a number of principles, one of which relates to cost recovery and states:[116]

> where arrangements require participants to pay a proportion of AEMO costs for ancillary services, charges should (where possible) be allocated to provide incentives to lower overall costs of the NEM. Costs unable to be reasonably allocated this way should be apportioned as broadly as possible whilst minimising distortions to production, consumption and investment decisions

Put in the context of this paper, the costs of providing the services contemplated by the rule change proposals should be allocated in a way that either incentivises behaviours that reduce

116 NER cl. 3 cl. 1.4 (a) (8)

the need (and cost) for the service and/or penalises behaviours that increases the need (and cost) for the service. Targeting cost recovery in this way can contribute to fixing the issues of decreasing levels of inertia, system strength or operating reserves more efficiently.

This is not necessarily an easy task and can involve a compromise between complexity, volatility, accuracy, and the utility of market signals provided.

Conversely, if costs are smeared in a non-targeted way, for example by adding the costs to the spot price so that all customers experienced an increase, the signals to encourage behaviours that fix the problem (e.g. investing in more of the service, operating plant in a way that doesn't impact power system security) would be blunted, and the problem may be perpetuated.

There are a range of different ways that costs are allocated and recovered in the NEM. For example:

- **Causer pays —** where costs are recovered from the parties that caused the need for a service to be procured. For example, the costs of procuring regulation FCAS are recovered from market participants who have been found to have contributed to the need for frequency regulation in the recent past.
- **User pays** — where the person or participant using the service or asset pays for it. This is a common form of cost recovery in the NEM. For example, it is used by networks when recovering the costs of an asset that is built for the sole use and benefit of one party.
- **Beneficiary pays** - similar to user pays, this model generally seeks to require those users that are seen to 'benefit' from the use of a service or asset, pay for it. For example, the arrangements for the recovery of system restart ancillary services costs can be considered, at least in part, to reflect this principle, as both generators and customers benefit from the service, and therefore pay equal shares for its provision.
- **Smeared recovery from a broad group of customers** — for example the recovery of RERT costs are smeared across those market customers that were consuming energy at the time of RERT activation based on their share of energy consumption.
- **Market participant fees** — where costs are recovered at regular intervals from registered market participants. For example AEMO's operating costs are recovered in this way.

QUESTION 22: COST RECOVERY ARRANGEMENTS

1. What are stakeholders' views on the appropriate approach to cost recovery for each of the system services discussed in this paper?
2. In each case, how can the cost recovery arrangements be developed to lower the overall costs of the NEM?

9.4 Implementation considerations

There are many reforms currently under way in the NEM. Stakeholders are invited to provide their views on how the rule changes in this paper may be prioritised with the other reform work being carried out by the market bodies.

This includes bundling reforms that are making changes to similar parts of the sector. For example, all reforms that require changes to participant bidding systems and adjustments to NEMDE being done at the same time. Or rather if these reforms should be sequential to allow for them to be more manageable. For example, the manner in which constraints are formulated and imposed.

Additionally, reforms that introduce adjustments to NEMDE must consider the implications of these modifications. For example, the Hydro Tasmania rule change proposes to introduce constraints to enable the delivery of a "synchronous service". Considerations should therefore include the extent to which these changes impact on NEMDE, introduce complexity and create scenarios that may result in perverse outcomes.

The AEMC is also interested in any practical limitations that stakeholders may face through the implementation of these proposed rule changes. This includes technological challenges and internal resourcing for training and education of any changes.

While these questions may be more tangible and better understood at the draft determination stage of these rule change requests, any information stakeholders can provide to the Commission on these issues is appreciated.

QUESTION 23: IMPLEMENTATION CONSIDERATIONS

1. What are the challenges or implications associated with implementing proposed arrangements discussed in this paper?
2. What are stakeholders views on the prioritisation or staging of the reforms to address the issues discussed in this paper?

10 LODGING A SUBMISSION

Written submissions on this paper must be lodged with Commission by **13 August 2020** online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function. Please select the most relevant project reference code to your submission from:

- ERC0290: Hydro Tasmania — *Synchronous service markets*
- ERC0300: TransGrid — *Efficient management of system strength on the power system*
- ERC0296: Infigen Energy — *Fast frequency response market ancillary service*
- ERC0295: Infigen Energy — *Operating reserve market*
- ERC0306: Delta Electricity — *Capacity commitment mechanism for system security and reliability services*
- ERC0307: Delta Electricity —*Ramping services*

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions on rule change requests.[117] The Commission publishes all submissions on its website, subject to a claim of confidentiality.

Again, the Commission welcomes interested stakeholders to contact us if they would like to discuss one or more of the rule change requests, or any related issues. Enquiries in relation to the system services rule change requests should be directed to the relevant project leader as per the table below:

Table 10.1: Contact information

RULE CHANGE REQUEST	AEMC PROJECT LEAD AND CONTACT DETAILS
Hydro Tasmania — Synchronous service markets (ERC0290)	James Hyatt James.Hyatt@aemc.gov.au ph. 02 8296 1628
TransGrid — Efficient management of system strength on the power system (ERC0300)	
Infigen Energy - Fast frequency response market ancillary service (ERC0296)	Ben Hiron Ben.Hiron@aemc.gov.au ph. 02 8296 7855
Infigen Energy — Operating reserve market (ERC0295)	Jessie Foran Jessie.Foran@aemc.gov.au ph. 02 8294 7864
Delta Electricity — Capacity commitment mechanism for system security and reliability services (ERC0306)	
Delta Electricity — Introduction of ramping services (ERC0307)	

117 This guideline is available on the Commission's website www.aemc.gov.au.

ABBREVIATIONS

Table 1: Abbreviations

AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
COAG	Council of Australian Governments
Commission	See AEMC
DER	Distributed Energy Resources
DPV	Distributed PV
ESB	Energy Security Board
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
FI	Frequency Indicator
FOS	Frequency Operating Standards
FUM	Forecast Uncertainty Measure
GPS	Generation Performance Standards
GW	Gigawatt
ISP	Integrated System Plan
LCR	Largest Credible Risk
LOR	Lack of Reserve
MASS	Market Ancillary Services Specification
MCE	Ministerial Council on Energy
MSOL	Minimum Safe Operating Level
MVA	Mega Volt Amp
MW	Megawatt
NEL	National Electricity Law
NEM	National Energy Market
NEMDE	NEM Dispatch Engine
NEO	National electricity objective
NER	National Electricity Rules
PASA	Projected Assessment of System Adequacy
PFR	Primary Frequency Response
PV	Photovoltaics (rooftop solar)
RERT	Reliability and Emergency Reserve Trader

RIS	Renewable Integration Study
SCADA	Supervisory Control and Data Acquisition
SSG	Synchronous Service Generator
SSRS	System Security and Reliability Services
TNSP	Transmission Network Service Provider
VRE	Variable Renewable Energy

A RECENT REFORMS

This appendix sets out the range of regulatory changes made by the AEMC in recent years. These reforms occurred to make sure the services required to keep the system operating securely and effectively are available in the amounts needed, as technologies and business models change.

The timeline below sets out the key AEMC projects and regulatory reforms that have occurred in recent years that relate to the provision of services needed to underpin a secure and reliable power system. Each regulatory reform is categorised by the time frame most relevant to the subject matter considered in the reform — either the investment, commitment, or dispatch time frame.

These projects offer a foundation from which the six new system services rule change requests will be considered.

A.1 AEMC reforms relating to planning and investment arrangements for system services

Table A.1: AEMC reforms relating to the investment time frame for system services

RULE	STATUS	DESCRIPTION
Values of customer reliability	Commenced May 2018	New rules to make AER responsible for establishing and regularly updating the values of customer reliability.
Managing the rate of change of power system frequency	Commenced July 2018	Makes TNSPs responsible for procuring minimum required levels of inertia or alternative frequency control services to meet minimum levels set by AEMO.
Managing power system fault levels	Commenced Oct 2017 - SA, July 2018 - NEM	Makes TNSPs responsible for maintaining minimum levels of system strength. Should a shortfall be identified by AEMO, the TNSP must procure system strength services to maintain the fault levels determined by AEMO. Also introduces 'do no harm' for new connecting generators.
Transmission connection and planning arrangements - connections aspects of the rule	Commenced July 2018	The connection aspects of this rule provide more choice, control and certainty for connecting parties, while at the same time making it clear that the incumbent TNSPs are accountable for providing a safe, reliable and secure transmission network
Generating system model guidelines	Commenced Sept 2018	Requires detailed information on how generators and networks perform to help AEMO plan for contingency events.
Generator three year notice of closure	Commenced Dec 2018	New requirement for large generators to give at least three years notice before closing.
Generator technical performance standards	Commenced Oct 2018	Updates the technical performance standards for connecting generators and the process for negotiating them.
Early implementation of ISP priority projects	Commenced May 2019	New rules to streamline the regulatory processes for key time-critical projects identified in AEMO's Integrated System Plan.
Transparency of new projects	Commenced Nov 2019	Enhances publicly available information about new generation projects, as well as allowing developers of these projects to register with AEMO to get access to key technical information such as network modelling data.

RULE	STATUS	DESCRIPTION
Register of distributed energy resources	Commenced Dec 2019	Makes AEMO responsible for establishing a register of distributed energy resources in the national electricity market, including small scale battery storage systems and rooftop solar.
Updated Generator compliance template	Commenced Dec 2019	Reliability Panel incorporated recent changes to generator technical performance standards and improved clarity and usability.
System restart services, standards and testing	Final determination Apr 2020	Seeks to enhance the frameworks for system restart and restoration. System restart services contribute to the overall resilience of the power system by enabling recovery following a major blackout.
Demand management incentive scheme and innovation allowance for TNSPs	Commences Mar 2021	Introduces demand management incentives for transmission businesses.

Source: AEMC

A.2 AEMC reforms relating to operational preparedness and commitment for system services

Table A.2: AEMC reforms relating to operational preparedness and commitment for system services

RULE	STATUS	DESCRIPTION
Declaration of LOR conditions	Commenced Dec 2017	New framework to allow AEMO to use a probabilistic approach when declaring lack of reserve conditions, and to report every quarter.
Reporting of aggregate generation capacity for MT PASA	Commenced May 2018	New arrangements for AEMO reporting on aggregate generation capacity to signal whether electricity supply is projected to meet demand in the medium-term.
Reinstatement of long-notice RERT	Commenced June 2018	Enables AEMO to contract up to nine months ahead of a projected shortfall under the RERT.
Participant compensation following market suspension	Rule commenced Nov 2018	Establishes a new compensation framework so that certain market participants who incur a loss during a market suspension event can be compensated.
Early implementation of ISP priority projects	Rule commenced May 2019	New rules to streamline the regulatory processes for key time-critical projects identified in AEMO's Integrated System Plan.
South Australian protected event	Declaration made June 2019	The Panel declared a protected event during periods of forecast destructive wind conditions in South Australia.
Application of the regional reference note test to the RERT	Rule commenced December 2019	Clarifies when intervention pricing should apply. This includes removing the use of intervention pricing for interventions to obtain services not traded in the market, such as system strength and voltage control.
Application of compensation in relation to AEMO interventions	Rule commenced December 2019	Affected participant compensation is no longer payable in connection with interventions which do not trigger intervention pricing, for example system strength directions. This rule actions a recommendation in the AEMC's final report on its Investigation into intervention mechanisms in the NEM.
Threshold for participant compensation following market suspension	Rule commenced December 2019	Changes the $5,000 compensation threshold for directed and affected participants so it applies per event rather than per trading interval.

RULE	STATUS	DESCRIPTION
Review of the System Black Event in South Australia on 28 September 2016	Final report published December 2019	Final report and recommendations that are designed to enhance the resilience of the power system.
Enhancement to the RERT	Rules commenced October 2019 and March 2020	New rules to enhancement, clarify and strengthen the RERT framework.
Short term forward market.	Final determination March 2020	Decision not to introduce a short term forward market given there is currently limited demand for short term hedge products in the market and that demand is sporadic and bespoke.
Victorian jurisdictional derogation – RERT contracting	Published March 2020	New arrangement to provide a derogation for Victoria to allow the Australian Energy Market Operator to contract for reserve electricity capacity under the Reliability and Emergency Reserve Trader mechanism on a multi-year basis.
Improving transparency and extending duration of MT PASA	Rule commences May-August 2020	Improves transparency of the MT PASA process, makes market information available when it is most needed and extends the period generation availability is published from two to three years.

Source: AEMC

A.3 AEMC reforms relating to system services and the dispatch time frame

Table A.3: Recent AEMC reforms relating to the system services in market dispatch

RULE	STATUS	DESCRIPTION
Frequency control frameworks review	Final report published July 2018	Final report and recommendations to support better frequency control in the long term. The final report included a frequency control work plan, developed collaboratively by the AEMC, AEMO and the AER. The work plan set out a series of action to improve the frequency control arrangements in the NEM. These actions included rule change requests to improve reporting and transparency around frequency control and frequency control markets.
Reliability Panel review of the frequency operating standard	Commenced January 2020	The standard has been restructured and consolidated to avoid duplication and improve the obligations it places on AEMO to manage the power system frequency
Monitoring and reporting on frequency control frameworks	Rule commenced January 2020	Established ongoing reporting requirements on AEMO in relation to frequency and frequency control performance; and on the AER in relation to the performance of frequency control ancillary services (FCAS) markets.
Mandatory primary frequency response	Rule commences 4 June 2020	Rule made requiring all scheduled and semi-scheduled generators to respond automatically to changes in power system frequency.

Source: AEMC

B INTERACTIONS BETWEEN AEMO'S RENEWABLE INTEGRATION STUDY AND AEMC SYSTEM SERVICES RULE CHANGE REQUESTS

This appendix details the areas of AEMO's Renewable integration study that will be key technical input into the rule change requests.

On 30 April 2020, AEMO published its stage 1 report for the Renewable integration study (RIS).[118] The RIS investigates and describes the requirements for operating the national electricity system securely through to 2025 focusing on key power system challenges associated with:

- system operability (network monitoring, scheduling, operator tools and processes)
- integrating distributed solar PV
- frequency management
- system strength
- variability and uncertainty.

The RIS stage 1 paper includes a list of actions and recommendations that are intended to address the key power system challenges.

Table B.1 sets out how the challenges identified in the RIS relate to and are interdependent with the package of system services rule change requests initiated in this paper.

It should be noted that in some cases the exact definition of services and the mechanisms for providing them will need to be worked on together. As AEMO's *Renewable integration study* continues, learnings will be incorporated into both the ESB's 2025 work and AEMC's assessment of the rule change requests, and incorporated into the development of future workplans.

118 AEMO, *Renewable integration study: Stage 1 report*, April 2020.

Table B.1: **Mapping AEMO's RIS to the AEMC system services rule change requests**

AEMO RENEWABLE INTEGRATION STUDY FOCUS AREA	KEY CHALLENGES IDENTIFIED BY AEMO	RELEVANT AEMC RULE CHANGE REQUESTS
System operability Ability to operate the power system within security and reliability standards	• An increasing penetration of wind and solar operating in the system is pushing the system towards minimum secure operating limits and increasing the complexity of the operating the power system. • Improved processes for scheduling of synchronous units are required to maintain minimum levels of inertia and system strength. The market design needs to adapt so all essential security and reliability services are provided efficiently, when required, and without operator intervention.	Hydro Tasmania — *Synchronous services markets* (ERC0290) Infigen — Operating reserve market (ERC0295) Delta — Ramping services (ERC0307) Delta — Capacity commitment mechanism for system security and reliability services (ERC0306) TransGrid — Centralised management of synchronous services (ERC0300)
Integrating distributed solar PV Balancing increasing levels of small, distributed generation with power system requirements	• The aggregate performance of the DPV fleet is becoming increasingly critical as penetrations increase. • Governance structures for the setting of DER technical performance standards, and enforcement of these standards, are inadequate. AEMO propose to submit a rule change request to set minimum technical standard for DER. • System dispatchability is decreasing as invisible and uncontrolled DPV increases in	Delta — Ramping services (ERC0307) Infigen — Operating reserve market (ERC0295)

AEMO RENEWABLE INTEGRATION STUDY FOCUS AREA	KEY CHALLENGES IDENTIFIED BY AEMO	RELEVANT AEMC RULE CHANGE REQUESTS
	the NEM.	
Frequency management Ability to set and maintain system frequency within acceptable limits	• AEMO's ability to model and plan the system impacted by a lack of consistency and certainty of PFR delivery from generation. (AEMO is in the process of implementing the Mandatory PFR rule to address this challenge over the near term) • Projected decreases in inertia in the system by 2025 will likely see an increase in the required volume or speed of response for frequency reserves. • The behaviour of inverter connected plant and run back schemes is not yet fully understood and adds to the uncertainty of system operation.	Hydro Tasmania — Synchronous services rule change (ERC0290) Infigen — Fast frequency response rule change (ERC0296) AEMO — Primary frequency response incentive arrangements rule change request (ERC0263) Delta — Capacity commitment mechanism for system security and reliability services (ERC0306)
System strength Ability to maintain the voltage amplitude, waveform and phase angle under system normal and contingent conditions within specifications	• System strength is declining in the NEM due to synchronous generator retirement or reduced operation, and increasing volumes of non-synchronous generation. • This has created complex challenges for AEMO particularly in relation to coordinating system strength resources and efficiently connecting new inverter-based generators particularly in weaker parts of the grid. •	AEMC - System strength investigation (EPR0076) Hydro Tasmania — Synchronous services rule change (ERC0290) TransGrid — Centralised management of synchronous services (ERC0300) Delta — Capacity commitment mechanism for system security and reliability services (ERC0306)

AEMO RENEWABLE INTEGRATION STUDY FOCUS AREA	KEY CHALLENGES IDENTIFIED BY AEMO	RELEVANT AEMC RULE CHANGE REQUESTS
	• AEMO is pursuing opportunities to improve the minimum system strength framework and improve system strength coordination across the NEM.	
Variability and uncertainty A sufficient portfolio of energy resources to balance supply and demand in every 5-minute interval	• The magnitude of peak ramps (upward/downward fluctuations in supply/demand) is forecast to increase by 50% over the next five years as a result of increasing wind and solar penetration. • AEMO's ability to model these fluctuations is limited, leading to forecast uncertainty and therefore a requirement for adequate ramping reserves to cover the increased variability at all times.	Infigen - Operating reserve market (ERC0295) Delta — Ramping services (ERC0307) Delta — Capacity commitment mechanism for system security and reliability services (ERC0306)

Source: AEMO, 2020, *Renewable integration study — Stage 1 Report*, April 2020, pp.8-11; AEMC analysis.

C ISSUES WITH THE ALLOCATION OF REGULATION SERVICE COSTS — CAUSER PAYS

The AEMC conducted a comprehensive review of the market and regulatory frameworks for frequency control as part of the *Frequency control frameworks review*, which concluded in July 2018. The review highlighted several issues to be addressed to support better frequency control in the long-term, and to enable the delivery of frequency control services from new technologies.

A key finding of the review was that the frequency control frameworks do not adequately incentivise market participants to provide a primary frequency response to support good frequency control under normal operation. The review consulted with stakeholders on a number of options to incentivise and reward the provision of primary frequency response. Of the options considered, stakeholders were largely in favour of making changes to the procedure by which AEMO recovers regulating FCAS costs (known as the 'causer pays' procedure) to facilitate the provision of incentive payments for primary frequency response.

Since that time, two rule change requests were submitted — one from AEMO and the other from private individual Dr Peter Sokolowski. Each of these rule change requests proposed to introduce a mandatory requirement for all scheduled and semi-scheduled generators to automatically respond to small changes in frequency either side of 50Hz, albeit through different proposed changes to the NER.

On 26 March 2020, the Commission made a final rule to require all scheduled and semi-scheduled generators in the NEM to support the secure operation of the power system by responding automatically to changes in the power system frequency. The Commission considers that a mandatory requirement for generators to activate an existing capability to provide primary frequency response will address the immediate need for improved frequency control in the NEM.

However, in the final determination for this rule, the Commission recognised that a mandatory requirement for narrow band primary frequency response is not a complete solution for the long term and, on its own, will not incentivise the provision of primary frequency response.[119] Further work needs to be done to understand the power system requirements for maintaining good frequency control, building on AEMO's *Renewable integration study*. This work should also consider the appropriateness of the mandatory requirement for narrow band primary frequency response and other alternative and complementary measures, including the potential for new market and incentive based mechanisms for frequency control.

Therefore, the final rule includes a sunset on the mandatory primary frequency response requirement there years in the future on 4 June 2023. The inclusion of the sunset demonstrates the Commission's commitment to the implementation of further reforms prior to June 2023 to appropriately value and reward the provision of frequency control services.

119 AEMC, Mandatory primary frequency response — final determination, 26 March 2020, p.24.

The existing arrangements for the allocation of costs associated with regulation FCAS provide a basis for the consideration of improved incentive arrangements for primary frequency response during normal operation. This Appendix summarises AEMO and the AEMC's findings and proposed improvements to the Regulation FCAS Contribution Factor Procedure or 'causer-pays' procedure.

In November 2018, AEMO published a final determination on amendments to the Causer Pays Procedure (renamed to the Regulation FCAS Contribution Factor Procedure).[120]In the final determination, AEMO made several changes to improve the causer-pays procedure and made a number of recommendations for further improvements, including through potential rule changes. The findings from this consultation are summarised in appendix c.2.

C.1 Findings and proposed improvements from the AEMC 2018 frequency control frameworks review

This section outlines the findings and proposed improvements from the AEMC's 2018 *Frequency control frameworks* review relating to the process for the allocation of regulation FCAS costs, known as 'causer-pays'.

C.1.1 Findings: limitations with the existing causer-pays framework

A principal objective of the regulation FCAS cost recovery arrangements is to place a financial incentive on market participants to act in a way that minimises the need to procure regulation services. By imposing the costs of the services on those market participants that give rise to the greatest need for the services, there is an incentive for those market participants to minimise adverse impacts to system frequency, and therefore minimise the overall requirements for the services. Such an arrangement should reduce the costs of regulation FCAS in the long term interests of consumers while achieving the objective of a secure power system.

In the 2018 review, the Commission set out that arrangements for financial incentives in relation to provision of frequency control services by market participants are likely to be efficient and effective where:

- transparent procedures allow participants to understand how their actions relate to the costs they are likely to incur
- there is an alignment of participants' impacts on system frequency and the costs they incur

Through the 2018 review, the Commission identified a number of issues with the current causer pays arrangements which may be resulting in inefficient outcomes. The key findings were:[121]

- A temporal disconnect between a market participant's contribution to the need for regulation FCAS and the costs charged to that market participant

120 AEMO, *Regulation FCAS Contribution Factor Procedure: Final Report and Determination*, 9 November 2018. Accessed at: https://aemo.com.au/consultations/current-and-closed-consultations/causer-pays-procedure-consultation

121 AEMC, *Frequency control frameworks review* - Final report, 26 July 2018, p.75.

- A lack of transparency and simplicity in the calculation of market participants' costs
- Charges for contributing to frequency deviations are not balanced through crediting or valuation of positive contribution factors

Each of these issues are described in further detail below.

A temporal disconnect between a market participant's contribution to the need for regulation FCAS and the costs charged to that market participant

AEMO is required to publish contribution factors with a notice period of at least ten business days prior to the application of those factors.[122] Currently, AEMO has chosen to adopt a 28-day averaging period for the calculation of the contribution factors as outlined in AEMO's causer pays procedure.[123] Taken together with the notice period, this means that the allocation of regulation FCAS costs for a particular 28-day period is based on performance contribution factors determined over a four-week period commencing around six weeks earlier.

The result of the 28-day averaging and misalignment of sample and application periods is that the volatility of regulation FCAS cost allocations is reduced. However, the incentive for market participants to help to correct frequency deviations in any single dispatch interval is muted.

Through the 2018 *review* the Commission proposed potential changes to the causer pays process to shorten and align the sample and application periods for regulation FCAS contribution factors. These changes were proposed since it was considered that the causer pays incentive was likely to be more effective if the performance measurement is closely aligned to the application of associated costs, preferably in real time.[124]

A lack of transparency and simplicity in the calculation of market participants' costs

The review set out that when incentive arrangements are not transparent, or are not easily understood by market participants they may not be effective in guiding the intended behavioural outcomes.

AEMO's causer pays procedure outlines the approach used to calculate contribution factors and to allocate costs. However, a common complaint of the procedures has been that it does not provide sufficient details for participants to calculate their own contribution factors.

Charges for contributing to frequency deviations are not balanced through crediting or valuation of positive contribution factors

The current causer pays arrangements allocate the costs of regulation FCAS to each participant in proportion to the extent to which its deviations from a linear trajectory exacerbate movements in frequency. Helpful deviations are only rewarded to the extent that they offset harmful deviations within a market participant's portfolio of generating units and loads. This creates an incentive for generators to track their output as closely as possible to a

122 Clause 3.15.6A(na) of the NER.

123 AEMO, Regulation FCAS contribution factor procedure – Final report and determination, November 2018, p.13.

124 AEMC, *Frequency control frameworks review* - Final report, 26 July 2018, pp.114-115.

linear trajectory to meet their dispatch target. The 2018 review concluded that this strategy has the effect of minimising harmful impacts on system frequency but also has the converse effect of minimising helpful contributions to system frequency.

C.1.2 Proposed improvements: addressing the limitations with the existing causer-pays framework

In the 2018 review, the potential changes to the causer-pays framework were suggested. These are detailed below.

Alignment and shortening of the sample and application periods

As discussed above, the current practice is to measure participant performance over a 28-day averaging period. This data is used to calculate contribution factors which are published by AEMO and apply for a 28-day period that commences 10 days after the publication. This means that the allocation of regulation FCAS costs for a particular 28-day period is based on performance contribution factors determined over a four-week period commencing around six weeks earlier.

The misalignment of the application of costs with the causers of the costs has the potential to give rise to unintended incentives. Market participants may gain financial benefit from acting in a way that is contrary to the intention of the incentive framework.

The 2018 review set out that an efficient framework is one in which there is an alignment of participants' impacts on system frequency and the costs they incur. As such, an alignment of sample and application periods under the causer pays arrangements may have some benefits.

The Commission therefore recommended that it is likely to be more appropriate to incentivise the provision of primary regulating response through a separate performance-based mechanism that targets automatic frequency response.[125]

In its *Regulation FCAS Contribution Factor Procedure: Final Report and Determination,* discussed in appendix c.2below, AEMO determined that the existing sample and application period should be retained.

Removal of the ten-day notice period

Under the NER, AEMO is required to publish contribution factors with a notice period of at least ten business days prior to the application of those factors.[126]

In the *Frequency control frameworks review*, the Commission identified that there may be benefits associated with the removal or reduction of this ten-day notice period based on the view that the causer pays incentive is likely to be more effective if the performance measurement is closely aligned to the application of associated costs, preferably in real time.

125 This mechanism is discussed in detail in Appendix A of the *Frequency control frameworks review* final report.

126 Clause 3.15.6A(na) of the NER.

The final report noted that any benefits from reducing or removing the ten-day notice period is only likely to be realised if the change is undertaken in combination with an alignment of the sample and application periods.

AEMO's *Regulation FCAS Contribution Factor Procedure: Final Report and Determination,* discussed in appendix c.2below, acknowledged the AEMC's analysis and identified that the notice period could be reviewed as part of a future rule change proposal.[127]

C.2 AEMO's recent review of the Regulation FCAS Contribution Factor Procedure

AEMO published a final determination on amendments to the Causer Pays Procedure (renamed to the Regulation FCAS Contribution Factor Procedure) on 9 November 2018.[128]

This concluded a two-stage consultation process that commenced on 5 December 2016. The new procedure took effect from 2 December 2018.

The main changes that AEMO made to the procedure were to:

- ignore 4-second samples in which the frequency indicator (FI) and system frequency are mismatched
- publish FI values close to real time
- consolidate and clarify the procedure.

AEMO intended to progress further changes through an NER rule change request. [129]

> The substantive amendments to the Procedure at this stage are limited to those necessary to address the issues directly related to the degradation of frequency control.
>
> ...After this consultation, AEMO intends to progress a work program that will involve proposing changes to the NER, as well as further consultation to finalise the necessary Procedure changes.

AEMO identified that it would deliver further changes by:

- consulting on and submitting a rule change
- consulting on and implementing minor process improvements
- conducting detailed analysis on performance assessment in light of the changing generation mix.

Table C.1 shows the status of the issues from AEMO's *Regulation FCAS Contribution Factor Procedure* following AEMO's final determination.

127 AEMO, *Regulation FCAS Contribution Factor Procedure: Final Report and Determination*, 9 November 2018, section 4.4.3, p. 14. Accessed at: https://aemo.com.au/consultations/current-and-closed-consultations/causer-pays-procedure-consultation

128 AEMO, *Regulation FCAS Contribution Factor Procedure: Final Report and Determination*, 9 November 2018. Accessed at: https://aemo.com.au/consultations/current-and-closed-consultations/causer-pays-procedure-consultation

129 Ibid, p. 2

Table C.1: **Overview of changes to causer pays procedure**

NO.	ISSUE	AEMO FINAL DECISION
1	Calculation of contribution factors when regulation FCAS requirements apply within a local region	Implement through rule change request
2	Ability for positive and negative performance to balance within a portfolio	No change
3	Ability for positive and negative performance to balance across the sample period	No change
4	The most appropriate sample period, notice period and application period	No change, but review the notice period as part of a rule change request
5	Treatment of non-metered market generation	Implement through rule change request
6	Resolving cases where all individual contribution factors are positive	Consult on and implement changes to the Procedure
7	Treatment of facilities with changing registration status during the sample period	Consult on and implement changes to the Procedure
8	Producing contribution factors when significant periods of input data are deemed unreliable or inapplicable	Consult on and implement changes to the Procedure
9	The appropriate form and granularity of published datasets	No change, but publish datasets
10	Consolidation and clean-up of procedure documentation	Amend procedure
11	Suitability of SCADA data as a basis for determining performance	No change, but consult on and implement changes to the Procedure for small negative SCADA values
12	The profile that is assumed when determining deviations	No change
13	Reference trajectory used to determine deviations	No change, but conduct detailed analysis in light of changing generation mix
14	Suitability of frequency indicator as weighting factor for determining performance.	Amend procedure and conduct detailed analysis in light of changing generation mix
15	Different treatment of contingency events when determining performance	Consult on and implement changes to the Procedure

NO.	ISSUE	AEMO FINAL DECISION
16	Aggregation of performance in the calculation of contribution factors	No change

Source: AEMO, *Regulation FCAS Contribution Factor Procedure: Final Report and Determination*, 9 November 2018. Accessed at: https://aemo.com.au/consultations/current-and-closed-consultations/causer-pays-procedure-consultation

The three issues that AEMO intended to implement via rule change requests are described in further detail below.

Table C.2: **Causer pays issues to be addressed via rule change**

NO.	ISSUE DESCRIPTION	AEMO DETERMINATION DETAILS
1	**Calculation of contribution factors when regulation FCAS requirements apply within a local region** Local regulation FCAS requirements arise when AEMO needs FCAS services to be provided in a specific region/s. When this occurs, AEMO recovers costs from all participants with a market generating unit or customer load in the region, using the NEM-wide (portfolio) contribution factor for each of those participants. While this approach ensures that local costs are only recovered from local participants, it also allows the performance of all of a market participant's appropriately metered facilities to affect the contribution factor for local requirements, including those that are outside the region of the local requirement.	**Initiate rule change** In its final determination, AEMO recommended that local contribution factors be adopted by a process of pre-calculating seven sets of factors through a change to the NER and subsequent Procedure and system changes.
4	**The most appropriate sample period, notice period and application period** The NER require AEMO to publish contribution factors at least ten business days in advance of the application period to provide a level of certainty to participants of their share of regulation FCAS costs. The current process is based on a 28-day sample and application period, which represents a balance between: •	**No change, but review the notice period as part of a rule change request** AEMO found an adequate case for changing the existing sample and application period had not been made during its determination process. However, AEMO recognised it is likely there will be a need for more dynamic quantities of regulation FCAS in the longer-term.

NO.	ISSUE DESCRIPTION	AEMO DETERMINATION DETAILS
	• the operational practicality of calculating contribution factors • the requirement to publish factors in advance in order to provide cost certainty • reflecting the most current frequency behaviour of facilities in a portfolio.	This is because the existing arrangements for recovery may no longer be appropriate if this need arises, and some form of real-time recovery (which might include real-time contribution factors) may be appropriate. AEMO suggested that AEMC *Frequency control frameworks review* should consider real time factors AEMO also found that Market participants are best placed to provide advice on the value-add that would result from the notice period.
5	**Treatment of non-metered market generation** The existing procedure considers non-metered sources of deviation, which include demand volatility associated with loads and generators that are not metered (primarily where they are not scheduled). The proportion of non-metered market generation has grown in recent years. However, the NER and the procedure only recover the contribution from non-metered sources (which forms the residual factor) from market customers on the basis of their energy consumption. In the issues paper, AEMO proposed that non-metered market generation be included in the recovery of the residual factor, which was supported in all stakeholder submissions.	**Initiate rule change** AEMO recommended that the NER be amended to allow the residual factor of regulated FCAS cost recovery to be apportioned to both market customers and non-metered market generation. This would more efficiently allocate the costs of regulation FCAS.

Source: AEMO, *Regulation FCAS Contribution Factor Procedure: Final Report and Determination*, 9 November 2018

D EXISTING SYSTEM SERVICE ARRANGEMENTS

The following sections provide a summary of the current regulatory frameworks that apply to each of the key system services discussed in this paper.

D.1 Frequency control

D.1.1 Understanding frequency control

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). When there is more generation than load, the frequency will tend to increase above 50 Hz. When there is more load than generation, the frequency will tend to fall.

Effective control of power system frequency requires the coordination of synchronous inertia and the provision of a range of frequency responsive energy reserves. Frequency control services act to re-balance and stabilise the power system frequency by varying the active power provided into or taken from the power system in response to frequency variations. 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 to re-balance supply and demand and to stabilise and restore the power system frequency.

Synchronous 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. This **synchronous inertia** acts to resist 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 system operating bands.

Following a contingency event, the initial **rate of change of frequency** is proportional to the size of the sudden change in supply or demand 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.

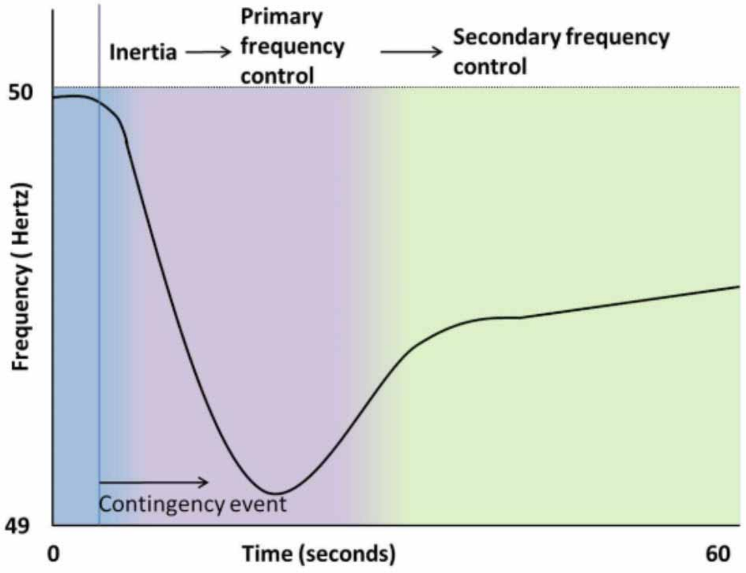
Effective control of power system frequency requires coordination of inertia and active power control services including primary and secondary frequency control.[130]

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.[131] The modification of generator output is generally provided through the generator governor systems that regulate the output of generating units.

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.

Tertiary frequency control refers to reserve generation capacity that operates over approximately five to 30 minutes following a frequency disturbance to reset the primary and secondary frequency control services. Tertiary frequency control is not explicitly required in the NEM because this function is achieved by the dispatch process that re-dispatches the generation every five minutes to balance demand and restore secure levels of regulating and contingency frequency control services.

Figure D.1: Integrated frequency control



Source: AEMC

130 AEMO, AEMC Frequency control frameworks review — AEMO Advice, 5 March 2018, p.5.

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

D.1.2 Achieving frequency control

AEMO is responsible for operating the power system in accordance with the requirements set out in the frequency operating standard (FOS), which is determined by the Reliability Panel in accordance with the NER. The FOS defines the range of allowable frequencies for the power system under different conditions, including normal operation and following contingency events. Generator, network and end-user equipment must be capable of operating within the range of frequencies defined by the FOS.[132]

On 26 March 2020, the AEMC published the *National Electricity Amendment (Mandatory primary frequency response) Rule 2020 No. 5*. This rule introduced a requirement for scheduled and semi-scheduled generators to help control power system frequency, by operating in a frequency responsive mode in accordance with the performance parameters defined by AEMO in the *Primary frequency response requirements*. Generators are not required to maintain additional stored energy to provide frequency response, unless they are enabled to provide frequency control ancillary services (FCAS).[133]

AEMO procures FCAS to provide responsive reserves to increase or decrease active power over a time frame that meets the requirements of the FOS.

AEMO and TNSP's also coordinate emergency frequency control schemes that automatically disconnect load or generation to 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 following sections provide further detail on two components of the regulatory framework that enable AEMO to manage frequency over operational time frames. These are:

- **The inertia framework**
- **Frequency control ancillary services**

D.1.3 The inertia framework

On 19 September 2017, the AEMC published the *National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017 No. 9* (Inertia Rule). The Inertia Rule establishes a framework for the management of inertia.

The rule places an obligation on AEMO to determine the inertia requirements for each *inertia sub-network* in accordance with the *inertia requirements methodology*.

The *inertia requirements* are specified as:[134]

- the minimum threshold level of inertia, being the minimum level of inertia required to operate an inertia sub-network in a satisfactory operating state when the inertia sub-network is islanded; and

132 The technical requirements or 'Access standards' for generation plant are set out in the Schedule 5.2 of the NER. The generator access standards define the range of the technical requirements for the capability and operation of generation equipment when negotiating a connection agreement.

133 NER Clause 4.4.2 (c1).

134 AEMO, Inertia Requirements Methodology, Inertia Requirements & Shortfalls, p. 3, June 2018

- the secure operating level of inertia, being the minimum level of inertia required to operate an inertia sub-network in a secure operating state when the inertia sub-network is islanded.

The rule also obligates AEMO to establish if any inertia shortfalls exist in each inertia sub-network. In the event an inertia shortfall has been identified, TNSPs have an obligation to ensure sufficient inertia network services are available to meet the secure operating level of inertia.[135]

Inertia service payments are exempt from the regulatory investment test for transmission (RIT-T), as is any proposed investment by TNSPs for inertia network services in relation to an inertia shortfall where the time by which the TNSP must make available inertia network services is less than 18 months after a notice of an inertia shortfall is given by AEMO.[136] In all other cases, a RIT-T is required.

D.1.4 Frequency control ancillary services

Frequency control ancillary services (FCAS) are procured by AEMO as market ancillary services through the NEM dispatch engine (NEMDE) as part of the 5-minute dispatch process. FCAS provide frequency responsive reserves that increase or decrease active power to dynamically stabilise supply and demand in the power system and control system frequency in accordance with the requirements set out in the FOS. AEMO's Market Ancillary Services Specification (MASS) defines the technical requirements for FCAS. The NER provides for eight ancillary service markets for frequency control ancillary services made of the following categories:

- **Regulating services** (raise and lower) — Used to correct a minor increase or decrease in frequency in between dispatch intervals. 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.
- **Contingency services** (raise and lower) — Used to provide balancing reserves 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. Under the NER contingency services are split up into three categories: fast, slow and delayed. AEMO defines the performance criteria for each service in the MASS. Under the current MASS the contingency services have the following general characteristics:[137]
    - **Fast services** — achieve target response within six seconds and sustain for 60 seconds.
    - **Slow services** — achieve target response with 60 seconds and sustain for five minutes.
    - **Delayed services** — achieve target response within five minutes and sustain for at least ten minutes.

135 Clauses 4.3.4(j) and 5.20B.4(a) of the NER

136 NER Clause 5.16.3(a)

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

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 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 of regulating FCAS is based upon a "causer pays" principle which is set out in the NER and detailed in AEMO's procedure, *Regulation FCAS contribution factor procedure*.[138] Under this methodology the average response of generators and loads to frequency deviations is monitored and used to determine a series of causer pays factors.

The costs of contingency raise services are recovered from *Market Generators*, as these services act 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 act to manage the disconnection of load from the power system.

D.2 Voltage management

Voltage is the electronic force of electrical potential between two points that gives rise to the flow of electricity. Nominal voltage is measured in kilovolt (kV). Voltage management is necessary to ensure the secure and reliable delivery of power throughout the network. It is important for preventing damage to electrical equipment, reducing transmission losses and maintaining the ability of the system to withstand and prevent voltage collapse.

Voltage control services in the NEM include:

- Fast and slow response voltage control.
- System strength.

D.2.1 Understanding fast and slow response voltage control mechanisms

Fast-response voltage control is achieved through the provision of large, rapid adjustments in reactive power to maintain stability in the power system. Achieving this requires maintaining adequate reactive reserves on the network in the event of system disturbances. The amount of reserve required depends on the severity of the contingency and power system conditions.[139]

Slow response voltage control describes the maintenance of power system voltage within acceptable ranges as supply and demand constantly changes. This is achieved through the continuous management, through minor adjustments, of reactive power in time scales of seconds or minutes.[140]

138 AEMO, *Regulation FCAS contribution factor procedure*, 2 December 2018.

139 AEMO, Power system security guidelines, September 2019, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715---Power-System-Security-Guidelines.pdf

140 AEMO, Power System Requirements, March 2018, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf

Reactive power capability is used to inject or absorb reactive power for the management of power system voltages and to assist the transfer and utilisation of active power. In this first instance, this is provided by generators through requirements to meet the mandatory technical standards set out in clauses S5.2.5.1 and S5.2.5.13 of the NER. These clauses set out the level of reactive power capability required for each generator, and the way that reactive power is *controlled and utilised*, respectively.[141]

D.2.2 Achieving fast and slow response voltage control mechanisms

NSPs have clear responsibility for planning their networks to allow for the management of voltage (including through the negotiation of technical standards with AEMO and a connecting generator). AEMO also has an operational role at a transmission level, being responsible for the dispatch of reactive power from scheduled generating units with the objective of setting the profile of the voltage throughout the high voltage network (needed to maximize the transfer capability of the network while maintaining the power system in a secure operating state). AEMO's dispatch instructions to scheduled generating units, semi-scheduled generating units, scheduled network services and scheduled loads can include reactive power injection or absorption.[142]

Under the NER, AEMO is required to determine the levels of reactive power reserve that are required to operate the power system. AEMO is also required to ensure that appropriate levels of reactive power reserves are available.[143] In addition, AEMO further determines the need for Network Support and Control Ancillary Services (NSCAS) that include the provision of reactive power reserves.[144] Specifically, AEMO can control the power flows of a transmission network for the control of voltage so that it is within defined limits by arranging the provision of reactive power facilities through voltage control ancillary services (VCAS).

VCAS is provided to the market under long term non-market ancillary service contracts negotiated between AEMO (on behalf of the market) and the participant providing the service. It can be provided by generators[145] and/or TNSPs utilising network reactive plant[146] to control voltage locally.[147] Payment is made through a mixture of enablement, testing and availability payments.[148]

141 The access standards in clause S5.2.5.13 specify how a generating system is required to regulate voltages at its connection point. This includes the mode in which reactive power is controlled, as well as the accuracy and controllability requirements.

142 NER clause 4.9.5(a)(2).

143 NER clauses 4.5.2(a) and 4.3.1(k) respectively.

144 NER clause 4.5.1(f).

145 Utilising the unused reactive power capacities or generating units running in synchronous generation mode (supply and absorb power without producing active energy) or generation mode (supply and absorb reactive power beyond, its performance standard, while producing active energy).

146 These assets are usually provided from the TNSP regulated asset base, but under some circumstances new assets can be installed and provided in response to AEMO's call for a tender for VCAS to fill a NSCAS gap.

147 AEMO, *Guide to Ancillary Service in the NEM,* April 2015, avaliable at : hhtps://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.pdf. and NER clause 4.5.1(g).

148 For example, if VCAS is provided by a synchronous condenser, payment will be made when the service is specifically enabled and additional payments will be made for costs incurred during annual testing of the service. In the case of the service being provided by static reactive plant, availability payments will be made for every trading interval that the service is available.84

AEMO uses the Var Dispatch Scheduler (VDS) as the primary tool for dispatching reactive power devices in the NEM.[149] The VDS is an automated system that determines the dispatch of reactive power devices.[150]

If the available reactive power reserves prove to be insufficient to keep voltages within acceptable limits, AEMO is required to take all reasonable actions to the extent necessary to return the voltages to acceptable limits.[151] Such actions could include directing participants such as generators to reduce their output or limiting flows within the transmission network.

D.2.3 Understanding system strength

System strength supports the stable operation of the power system. It keeps generators connected and operating securely, while also helping to protect the system from faults, such as those that may occur following a lightning strike on a power line.

System strength is a characteristic of an electric power system that relates to the size of the change in voltage following a fault or disturbance on the power system as well as stability of the voltage waveform during normal operation. Essential levels of system strength are required continuously available to maintain a secure power system. Low levels of system strength can jeopardise the ability of generators to operate correctly.

System strength can also be beneficial above this essential level to allow inverter -based generators to operate at higher output. Alleviating constraints on inverter-based generation increases competition in the provision of energy, thereby lowering costs to consumers. In addition, system strength is also needed to provide hosting capacity, which is the capability of a network to support the effective connection of, and export of energy by, as many generators as is efficiently possible. Finally, system strength enhances system resilience, which is the ability of the power system to remain stable following rare, but severe disturbances.

D.2.4 Achieving system strength

The current system strength frameworks were put in place in 2017 to address immediate system strength issues and concerns. Two frameworks were established by the *Managing power system fault levels rule 2017*[152] (the system strength rule) to address system strength issues:

1. The “do no harm” frameworks: new connecting generators are required to deliver system strength commensurate to their 'harm' to the local fault current as a consequence of their connection.

149 AEMO, Power system security guidelines, September 2019, available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715---Power-System-Security-Guidelines.pdf

150 Dispatch is determined by considering the availability of reactive power devices, voltage limits and pre-contingency and post contingency voltage violation

151 NER clause 4.5.2(b).

152 National Electricity Amendment (Managing power system fault levels) Rule 2017 No. 10

2. The minimum system strength framework: addresses declining levels of system strength as synchronous generators retire or reduce their output. AEMO identify shortfalls of system strength, with TNSPs then working to address these expected shortfalls.

The system strength rule defined the concept of a system strength service in the NER as a "service for the provision of a contribution to the three-phrase fault level" at a given location in the transmission network. This means that fault current is used as a measurable proxy for the provision of system strength at a given location. Therefore, stronger power systems typically have higher fault current levels (capacity to handle current flowing as a result of a fault or disturbance).

More recently, system strength has become a catch-all term for the ability of the power system to return to stable operating conditions following a physical disturbance. While these definitions illustrate elements of what could comprise a system strength service, other elements of this critical service are still coming to light.

The Commission is currently working with the ESB, AEMO, AER and other stakeholders through the *Investigation into system strength frameworks in the NEM* to clarify what a system strength service is, and what role it plays in a rapidly changing power system. Furthermore, this definition may have different aspects recognising that the service can be procured both passively and actively.

D.3 Reserve services

D.3.1 Understanding reserve services in the context of broader reliability framework

A reliable power system is one that has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence.

Delivering a reliable power system requires a sufficient overall portfolio of energy resources that allows for constant real-time balancing of supply and demand. Achieving this balance, both dynamically from one dispatch interval to another, and over longer-term planning time scales, requires a coordinated mix of operational and investment tools and mechanisms.

Over both operational and investment time frames, power systems are managed and designed to have enough spare capacity to meet the full range of reasonably foreseeable outcomes. There are different types of capacity that are procured to meet these outcomes, which differ in the way they are able to be called into use.[153] In the NEM, this includes:

1. **Bulk Energy -** Bulk energy is the core product supplied by the power system. The NEM's performance in meeting the reliability standard is measured in terms of whether there is a shortfall in the supply of bulk energy. This service represents the provision of electricity from generators and demand response providers, to match demand from consumers, at least cost (given the constraints in the system at a particular point in time). It relates to the overall energy adequacy of the aggregated portfolio of available energy resources.

153 While network transport capability and the adequacy and capacity of transmission and distribution services is a key factor in achieving resource adequacy, this section will speak only to the generation of energy resources, rather than the transportation of it, to more appropriately address the rule changes at hand.

2. **In-market reserve available to be drawn upon** — This refers to the non-dispatched capacity available to be drawn upon to meet unexpected demand growth and/or reductions in supply. This reserve depends on the amounts of generation, demand response, and scheduled market network service provider capability at any point in time.[154] At present, the NEM does not include an explicit payment or procurement arrangement to ensure this spare capacity, or 'headroom' is available. Instead, market participants typically make commercial decisions to maintain headroom within their portfolios to ensure they can meet their contractual obligations, or respond opportunistically to scarcity price signals in the wholesale market. Historically, policy reforms have focussed on gaining more visibility of the volume and accessibility of this headroom. For example, AEMO forecasts the scarcity of these reserves over a seven-day time frame using the 'lack of reserve' (LOR) conditions framework, and AEMO informs the market of 'lack of reserve' (LOR) conditions to encourage a response from market participants to provide more capacity into the market.
3. **Emergency reserves** - Where required to meet the reliability standard, AEMO may elect to contract for out-of-market reserves through the Reliability and Emergency Reserve Trader (RERT) provisions in the NER. This occurs during periods where risks of supply disruptions have been indicated. The RERT is an existing intervention mechanism that allows AEMO to contract for additional, emergency reserves such as generation or demand response that are not otherwise available in the market. They are additional out of market reserves because they are in addition to the headroom that is maintained by the market as part of the usual operation of the power system. The RERT is an important part of the regulatory framework, allowing AEMO to use a safety net at times when a shortfall in market reserves is forecast, or where practicable, to maintain power system security. These additional reserves are commonly referred to as "emergency reserves", since they are used as a last resort when the market has not otherwise provided reserves to reduce the likelihood of blackouts, typically during periods when the demand supply balance is tight.

D.3.2 Achieving efficient reserve levels

The NEM's bulk energy and reserve requirements are delivered by the NEM's reliability framework. The reliability framework aims to deliver enough power supply and demand response to satisfy the reliability standard through market mechanisms to the greatest extent possible.

Under current NEM frameworks, the reliability standard is the primary criterion used to evaluate whether the power system has sufficient supply resources to meet future consumer demand. The reliability standard is expressed in terms of unserved energy. Under the reliability standard, unserved energy must not be more than 0.002 per cent of the total energy demanded in a given year.

Currently, AEMO operationalises the reliability standard through its forecasting processes, which provide information to market participants and potential investors. The NER give AEMO

154 Reserves are defined in Chapter 10 of the rules

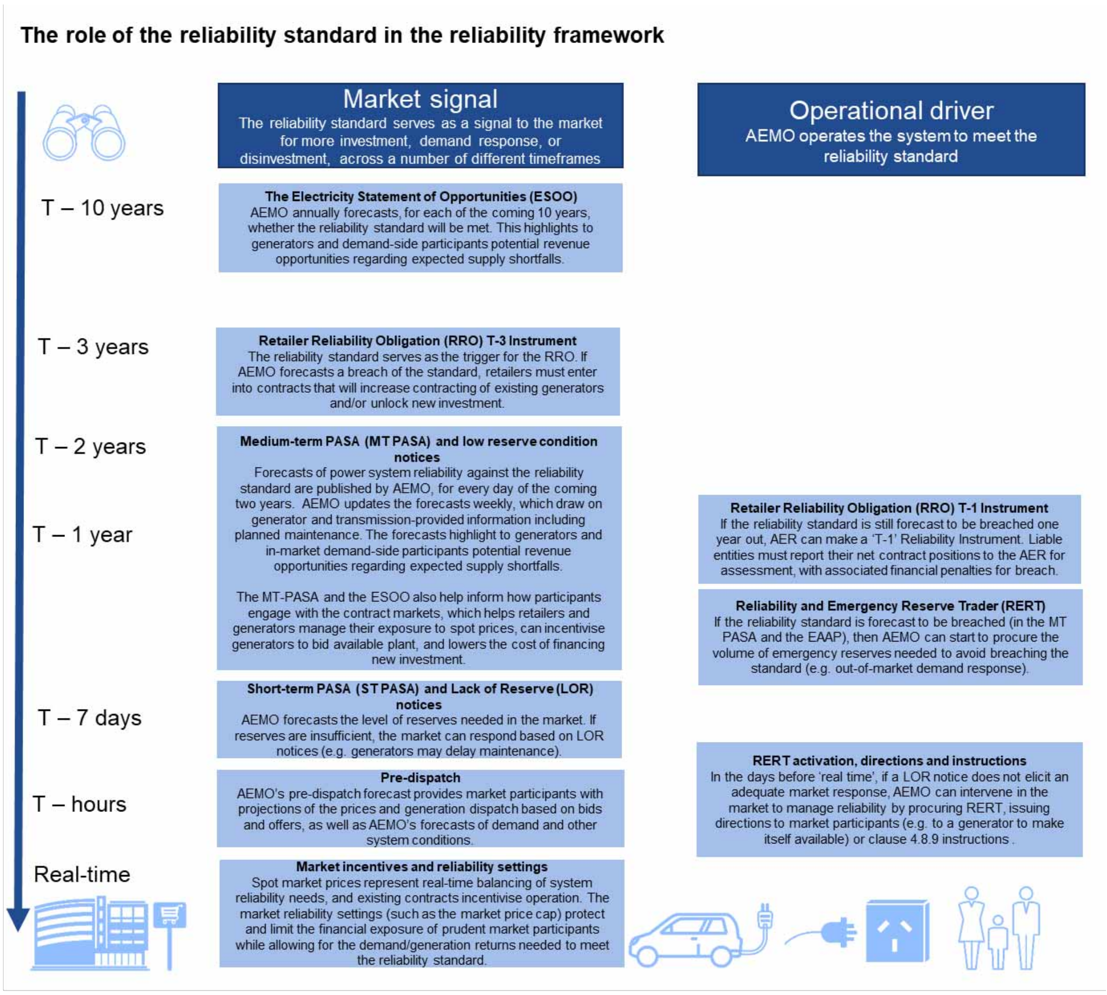
the flexibility to evolve and adapt its approach to how it operationalises the reliability standard over time.

The role of the reliability standard in the NEM's reliability framework is two-fold. It serves as:

- a market signal - the standard signals to the market commercial opportunities for more investment in generation, demand response and contracting.
- an operational driver - AEMO operates the system to meet the reliability standard.

The arrangements that enable these roles, ultimately enabling the NEM to meet the reliability standard, are detailed in the diagram below.

Figure D.2: The role of the reliability standard in the reliability framework



Source: Reliability Panel

In March 2020, following advice from the ESB, COAG Energy Council agreed to implement interim measures to deliver further reliability by establishing an interim out-of-market capacity reserve and amending triggering arrangements for the Retailer Reliability Obligation

(RRO). The measure, which the ESB is currently developing, allows AEMO to procure reserves for contract terms of up to three years, replacing the long notice RERT. They aim to keep unserved energy to no more than 0.0006% in any region in any year.[155]

Information and forecasts to support reliability

As illustrated in Figure D.2 above, the NEM has many features that provide information to the market ahead of real time. For example forecasting processes such as the pre-dispatch process which operates over a 24 hour period prior to actual dispatch, and the projected assessment of system adequacy (PASA) allow AEMO the flexibility to change its reliability assessments about expected levels of unserved energy based on new information. This includes information about generation availability (e.g. whether a generator is out on maintenance or not) and changing weather conditions.

Short term (ST-PASA) operates over a three-week horizon and provides information to market participants on the expected level of short-term capacity reserve and hence the likelihood of interruptions due to a shortage of power. Medium term (MT-PASA) assesses the adequacy of expected electricity supply to meet demand across a two-year horizon. Long Term PASA (LT-PASA) is undertaken by AEMO on an annual basis, as part of the publishing of the Electricity Statement of Opportunities (ESOO) and considers the 10-year planning horizon for generation, demand side programs, and network capacity.

AEMO considers different maximum demand outcomes, different weather conditions and different supply availability combinations in this forecasting, and updates its assessment at regular intervals as real-time approaches. From this, market participants and AEMO can make decisions based on the latest and most accurate information available. AEMO also uses this information to assess whether it needs to intervene in the market.

When considering markets for bulk energy, existing regulatory arrangements provide incentives for investment in not only the correct quantity but also the appropriate type of generation capacity and potential demand response. For example, commitment decisions can be influenced by the ability of plant to ramp quickly and the costs associated with committing and de-committing units, improving the business case associated with investing in types of generators with these capabilities. This includes through reducing the risk associated with entering into contracts for a large proportion of their capacity.

Participants have the flexibility to adjust their position in response to new information as it becomes available. This includes changes in market conditions as well as responding to offers or bids of other participants. The widespread nature of rebidding implies that market participants continually re-optimise their own portfolios in response to new information and reflect this through adjusting their bids.

155 COAG Energy Council, Meeting communique, 20 March 2020, p. 1.

THE DOCUMENT HAS ERRORS

1. The target of the Hyperlink which is an anchor with name '#_f9520287-3a7a-4527-911f-78e7c25300c5' does not exist.