RULE

Australian Energy Market Commission

DIRECTIONS PAPER

NATIONAL ELECTRICITY AMENDMENT (OPERATING RESERVE MARKET DIRECTIONS PAPER) RULE

PROPONENTS

Iberdrola Australia Limited
Delta Electricity

3 AUGUST 2023

INQUIRIES

Australian Energy Market Commission
Level 15, 60 Castlereagh Street
Sydney NSW 2000

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

Reference: ERC0295

ABOUT THE AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

ACKNOWLEDGEMENT OF COUNTRY

The AEMC acknowledges and shows respect for the traditional custodians of the many different lands across Australia on which we all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

COPYRIGHT

CITATION

To cite this document, please use the following:
AEMC, Operating reserve market directions paper, Directions Paper, 3 August 2023

SUMMARY

This paper sets out the AEMC's proposed way forward for the operating reserve rule change requests

1 An operating reserve market would explicitly value reserves in the National Electricity Market (NEM) by centralising reserves procurement. While it could provide greater visibility of market participants' reserve decisions helping to manage risks, the Commission considers that it would not offer any performance improvements relative to the current arrangements, and would also likely introduce additional costs for the market.

2 The Commission is therefore proposing not to recommend the implementation of an operating reserve market. This view is supported by modelling, showing that a fleet that evolves to firm renewables with very flexible storage technologies:

- will likely be well-placed to manage net demand uncertainty in operational timeframes (five minutes to an hour) so long as participants have sufficient storage to account for such uncertainties
- should be reasonably well-placed to manage net demand needs over the course of a full day, so long as sufficient depth of charge and other resources are available to manage the potential for longer duration events to occur.

3 Projections of investment suggest that we're heading towards such a fleet.

4 This view was generally (though not universally) supported by stakeholders consulted as part of the AEMC's consideration of these rule change requests.

5 The Australian Energy Market Operator (AEMO) is progressing a number of initiatives to support the existing market arrangements to best meet the needs of the power system during the transition. These initiatives are focused on improving net demand forecasts and redeveloping the short-term projected assessment of system adequacy (ST PASA). AEMO's focus on these areas is providing value to the market given the pace and scale of change occurring.

6 The Commission is considering whether there is merit in pursuing two additional incremental improvements alongside the initiatives that AEMO is already progressing. These are:

1. **Develop and publish more information to the market**, with a particular focus on energy-limited plant. This would involve AEMO receiving information on storage including state of charge and publishing it in either pre-dispatch or dispatch, with the aim to address the need for more information on the flexibility and duration of plant.
2. **Procurement of frequency control ancillary services (FCAS) at a regional level,** or alternately limiting the amount of FCAS procured from a single region to increase the amount of FCAS procured in other regions. This could allow for frequency stabilisation within a region following a rapid and unexpected change in variable renewable energy (VRE) output, without being limited by interconnector headroom between regions. It could also allow for transmission infrastructure to be used more effectively and may improve network utilisation, potentially avoiding some transmission spend as we move through the transition.

7 We are interested in stakeholder views on this proposed direction and incremental improvements. Submissions are due 31 August 2023. The process for making a submission is outlined in section 1.9.

Energy reserves in today's NEM

8 Meeting the NEM's reliability and security objectives requires sufficient energy, frequency control services and reserves.

9 'Operating reserves' are defined as the capability to respond to large continuing changes in energy requirements, with minimum levels required for the system operator to maintain system security and reliability. Such reserves are currently provided 'in-market' informed by the collective decisions of many participants in aggregate. These are not explicitly priced, but implicitly. If changes occur and insufficient in-market reserves are available, the consequences for customers can be significant. These include the costly purchase of backup reserves out-of-market and the potential for load shedding and blackouts.

Reserve needs are increasing, though this is likely transitory

10 The available evidence indicates that the reserve needs of the power system are generally being adequately and efficiently met under the current market arrangements. System reliability performance across the last decade has been largely good, notwithstanding some instances where a lack of reserves was declared.

11 Increases in the penetration of VRE generation, however, mean that predicting the near-future reserve needs is becoming more challenging. Given VRE generation, including distributed solar photovoltaic (PV), is harder to forecast, we are seeing more frequent instances of unexpected changes in the energy system. This has led to a corresponding increase in reserve requirements and more frequent procurement of out-of-market reserves, including the Reliability and Emergency Reserve Trader (RERT).

12 It is likely that as the transition proceeds, reserve needs will continue to increase. Analysis by AEMO supports this.

13 In the longer term, we expect reserve requirements to moderate. This is because we anticipate greater technological and geographic diversity of VRE generation, and improvements in forecasting capabilities, as the energy transition proceeds. These trends can limit the frequency and impact of unexpected events, and therefore moderate any increases in variability and uncertainty in power system conditions.

The current arrangements can continue to efficiently meet reserve needs into the future

14 The key question considered in this directions paper is therefore whether the generation fleet will adapt in a way that provides sufficient capacity to manage a transitory increase in reserve needs, and whether it will do so efficiently.

15 Based on the available evidence and analysis of the current market framework, the

Commission considers that it is very likely that the answer to this question is *yes*. The existing market arrangements, in our view, are sufficiently flexible to manage the potential for a transitory increase in reserve needs, notwithstanding that there may be some bumps along the road as the transition proceeds.

16 The principal mechanism underpinning the ongoing appropriateness of the current market framework to meet reserve needs is the financial risks imposed on market participants. We anticipate that these risks will be amplified during the transition as the system's need for reserves temporarily increases.

17 Combined with their incentive to manage financial risks, we expect market participants' resources and analysis to result in sufficient commitment of in-market reserves to meet the physical needs of the system in operational timeframes.

Long duration storage is essential to meeting reserve needs

18 Looking beyond operational timeframes, investment signals are being addressed through work on market settings, and government schemes, in combination with the signals already provided by the current arrangements. It will be important that these incentives deliver the right kinds of plant on the system.

19 Modelling conducted to support our analysis highlighted the importance of highly flexible capacity, including batteries and pumped hydro, that takes seconds/minutes to start up and that can sustain this capacity over several hours. The modelling illustrated that across all regions, the more flexible and enduring the generation fleet is, the more likely it can respond to unexpected events and reduce any energy gaps in the operational timeframe.

20 Analysis of the investment pipeline suggests that existing incentives and government schemes are working to deliver flexible and enduring capacity, such as battery storage and pumped hydro.

The Commission is proposing not to recommend implementation of an operating reserve market

21 Stakeholders, including the rule change proponents, have questioned whether an operating reserve service could improve the system's ability to meet the need for reserves.

22 An operating reserve market, in our view, would offer any reliability improvements relative to the current market arrangements. It may provide some value by making market participants' reserve decisions more visible and certain ahead of dispatch, mitigating risks, however we consider that this would be outweighed by the costs that an operating reserve market would impose on consumers.

23 These include direct costs, including implementation costs for AEMO and for market participants who may need to upgrade their systems to accommodate trading in a new market. There would also likely be indirect costs associated with an operating reserve market, including that it would likely be unhedgeable, creating risks and therefore costs for market participants.

24 An explicit operating reserve market is not a tool to provide investment signals. Indeed, there is a risk that such a market may dilute investment signals, particularly for fast-start plant, given an operating reserve market would have a lengthy procurement window of 30 minutes or more. Implementing an operating reserve market is also at odds with the direction of recent reforms, particularly five-minute settlement, which involved moving to stronger financial signals to incentivise investment in fast-start plant.

AEMO's technical advice has been integral to our assessment

25 AEMO provided detailed technical advice to the AEMC to support our assessment of these rule change requests. AEMO's advice is published on our website and has informed the development of this paper, providing for a more considered assessment of the merits of an operating reserve service. While the Commission's current direction is to not implement an operating reserve market, AEMO's advice has been important to our considerations.

The Commission is seeking feedback on whether there is merit in pursuing two incremental improvements alongside AEMO's initiatives already underway

26 Given the significant regulatory changes already underway (such as transmission access and frequency performance payments) the Commission considers that simple and flexible solutions would likely result in greater benefits and lower costs for consumers. This also provides the opportunity to observe the future fleet's response to changes in market signals, before introducing any further changes.

27 AEMO is already progressing a number of initiatives aimed at supporting the market in meeting increasing variability and uncertainty. These initiatives have a particular focus on improving net demand forecasts and redeveloping ST PASA, and AEMO's focus on these areas is, in the Commission's view, providing value to the market.

28 Beyond AEMO's existing initiatives, we are considering whether there is merit in pursuing further incremental improvements to the existing market design. These improvements focus on the immediate and known needs of the power system and could adapt as the needs of the power system, and our understanding of it, develop in the longer term.

29 The two proposed incremental improvements are:

1. **Develop and publish more information to the market**, with a particular focus on energy limited plant. This would involve AEMO receiving storage and state of charge information and publishing it in either pre-dispatch or dispatch, with the aim to address the need for more information on the flexibility and duration of plant.
2. **Procurement of FCAS at a regional level,** or alternately limiting the amount of FCAS procured from a single region to increase the amount of FCAS procured in other regions. This could allow for frequency stabilisation within a region following a rapid and unexpected change in VRE output, without being limited by interconnector headroom between regions. It could also allow for transmission infrastructure to be used more

effectively and may improve network utilisation, potentially avoiding some transmission spend as we move through the transition.

30 We are interested in stakeholder views on the proposed incremental improvements.

How to make a submission

We encourage you to make a submission

31 Stakeholders can help shape the solutions by participating in the rule change process. Engaging with stakeholders helps us understand the potential impacts of our decisions and, in so doing, contributes to well-informed, high quality rule changes.

How to make a written submission

Due date: Written submissions responding to this consultation paper must be lodged with Commission by 31 August 2023.

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code ERC0295. If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission.

You may, but are not required to, use the stakeholder submission form published with this consultation paper.

Tips for making submissions are available on our website.[1]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[2]

What to include in a submission

32 The Commission is most interested in stakeholders' views on:

- **Question 1:** do you agree with the Commission's decision not to recommend the implementation of an operating reserve market?
- **Question 2:** is there merit pursuing the two additional incremental improvements, including formalising these in the Rules framework?
- **Question 3:** are there any other incremental improvements that should be pursued in the absence of an operating reserve market being implemented?

Other opportunities for engagement

33 There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions.

1 For more information see https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3.

2 For more information see https://www.aemc.gov.au/contact-us/lodge-submission.

34 Our next technical working group meeting will be scheduled in September or October 2023.

35 For more information, please contact the project leader with questions or feedback at any stage.

Project leader:	Shannon Culic
Email:	Shannon.culic@aemc.gov.au
Telephone:	(02) 8296 1640

CONTENTS

APPENDICES

FIGURES

1 INTRODUCTION

1.1 This paper sets out our proposed way forward

This directions paper sets out the Commission's proposed way forward on a potential operating reserve market, for stakeholder feedback. We are proposing:

- Not to implement an operating reserve market design, given:
  - there is evidence that assets are responding to existing price signals to make reserves available when needed, and our analysis suggests that this would continue to happen into the future
  - the introduction of a new 'operating reserve' market to manage forecast uncertainty could provide greater visibility of market participants' reserve decisions potentially mitigating risk, however, the Commission considers that it would not offer any performance improvements relative to the current arrangements, and would likely introduce additional costs for customers
  - the introduction of an operating reserve market is at odds with the direction of recent reforms, particularly five-minute settlement, and may dilute the investment signals for fast-start plant
  - there is evidence that the generation fleet is evolving to a highly flexible and enduring capacity fleet, including batteries and pumped hydro, that can respond quickly to energy gaps in the operational timeframe and sustain this response for several hours.
- Instead, we:
  - note existing work AEMO is doing to improve information transparency and forecasting, with relation to security and reliability, which we consider to be beneficial in this space
  - explore whether there is merit in pursuing incremental improvements alongside the above initiatives to better manage forecast variability and uncertainty as the transition proceeds including:
    - ways for AEMO to seek more and better visibility and information on storage/state of charge
    - better ways of managing contingency risks through frequency to manage uncertainty in a sub-5-minute timeframe and to reduce overall costs for consumers through the transition.

We are interested in stakeholder feedback on our proposed direction and whether the incremental improvements discussed in chapter 5 could provide value.

1.2 This project considers variability and uncertainty in power system conditions

This paper is part of the Commission's considerations of two rule change requests — from Iberdrola Australia (previously Infigen Energy) and Delta Electricity — that raise issues relating to the ability of the current energy and frequency control market frameworks to address variability and uncertainty in power system conditions in the transition.[3]

This paper is an update to a previous directions paper published by the AEMC in 2021, which sought feedback on both the need for an explicit in-market reserve service and several options to procure such reserves, as well as several incremental improvements that may be worth considering.[4] Further detail on the earlier consultation and directions paper can be found in appendix B.

In 2021, the Commission extended the statutory timeframe to publish its draft determinations for these requests. This provided the opportunity to consider:

- the progression of work relating to a potential capacity market, and more recently the Commonwealth Government's capacity investment scheme
- evidence from observing the operation of the market under five-minute settlement (5MS) and wholesale demand response, which were implemented in October 2021
- detailed technical advice provided by AEMO relating to how key elements of an operating reserve market could be designed and implemented, which was provided to the AEMC in November 2022.[5]

There is now further detail on the capacity investment scheme, we have observed the operation of the market under five-minute settlement and with wholesale demand response for a sufficient period of time, and AEMO has provided its technical advice. We consider that it is now timely to propose a way forward and get feedback on this approach.

Figure 1.1: Project timeline

Source: AEMC

3 For more information see appendix A or visit the project page https://www.aemc.gov.au/rule-changes/operating-reserve-market.

4 For more information see https://www.aemc.gov.au/sites/default/files/2021-01/Reserve%20services%20directions%20paper%20-%205.01.2021%20-%20FINAL.pdf.

5 AEMO's Technical Advice can be found at https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf.

1.3 Our assessment considers the NEO and the system services objective

1.3.1 The Commission will make a decision in line with the NEO

Under the National Energy Law (NEL), the AEMC may only make and amend the electricity rules if doing so will contribute to the national electricity objective (NEO).[6]

> The *National Electricity Objective* ('NEO') is to promote **efficient** investment in, and efficient operation and use of, electricity **services** for the long-term interests of **consumers** of electricity with respect to:
>
> - **price**, **quality**, **safety**, **reliability** and **security** of supply of electricity; and
> - the **reliability**, **safety** and **security** of the national electricity system.

In determining a direction for the two rule change requests, the Commission has considered whether the proposed rules would contribute to the NEO, the system services objective that was developed at the initiation of the AEMC assessment process, as well as the specific assessment principles for this rule change.

1.3.2 We have also considered the system services objective

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. It is important to develop a specific approach to assessing the implications for the variables identified in the NEO.

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

More information on the system services objective can be found in the AEMC's consultation paper.[7]

6 Section 88 of the NEL.

7 For more information see https://www.aemc.gov.au/sites/default/files/2021-01/Reserve%20services%20directions%20paper%20-%205.01.2021%20-%20FINAL.pdf.

1.3.3 The NEO will be amended to include an emissions reduction objective

In May 2023, Energy Ministers approved amendments to the national energy laws to implement their previous decision to incorporate an emissions reduction objective into the NEO, National Energy Retail Objective, and National Gas Objective, with amendments expected to take effect by September 2023.

The legislative process to introduce an emissions reduction objective into the national energy objectives is currently in train. While this directions paper reflects the objective currently included in the NEL, future publications in relation to these rule change requests will adopt the new objective should the relevant legislative process be complete by that time.[8]

1.3.4 The Commission also considers the regulatory impacts of the proposed changes

Our regulatory impact analysis methodology

Considering the NEO and the issues raised in the rule change requests, the Commission proposes to assess this rule change request against the set of criteria outlined below. These assessment criteria reflect the key potential impacts of the rule change requests. We consider these impacts within the framework of the NEO.

The Commission's regulatory impact analysis may use qualitative and/or quantitative methodologies. The depth of analysis will be commensurate with the potential impacts of the proposed rule change. We may refine the regulatory impact analysis methodology as this rule change progresses, including in response to stakeholder submissions.

Consistent with good regulatory practice, we also assess other viable policy options — including not making the proposed rule and making a more preferable rule — using the same set of assessment criteria and impact analysis methodology where feasible.

Assessment criteria and rationale

The Commission assesses each rule change request it has 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, the Commission is considering the following criteria for these rule change requests:

- **Promoting power system security and reliability**: 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 changes, weighed against the likely costs. A key consideration here is making sure that the reliability and security frameworks work together to achieve desired outcomes. The inter-relationships between other reforms is a key consideration for the Commission in this project.

8 Department of climate change, energy and environment and water, 2023. Energy and climate change ministerial council meeting 19 May 2023 communique, https://www.energy.gov.au/sites/default/files/2023-05/EMSG1%20final%20communique%2019%20May%202023_0.docx.

- **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.
- **Technology neutral**: Regulatory arrangements should be designed to take into account the full range of potential market and network solutions.
- **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.
- **Transparent, predictable and simple**: The market and regulatory arrangements should promote transparency and be predictable, so that market participants can make informed and efficient investment and operational decisions.
- **Cost:** Regulatory change typically comes with some implementation costs for regulators, the market operator and/or market participants. These costs are ultimately borne by consumers. The cost of implementation should be factored into the overall assessment of any change. Increased complexity comes with increased costs, and therefore the level of complexity of regulatory change should be justified by the benefits achieved.

1.4 We encourage all stakeholders and interested parties to make a submission

Stakeholders can help shape the solution by participating in the rule change process. Engaging with stakeholders helps us understand the potential impacts of our decisions and, in so doing, contributes to well-informed, high-quality rule changes.

Due date: Written submissions responding to this directions paper must be lodged with the Commission by 31 August 2023.

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code ERC0295.[9]

Tips for making submissions on rule change requests are available on our website.[10]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we consider are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[11]

Further opportunities for engagement: There are other opportunities to engage on this project, such as one-on-one discussions with the project team. If you are interested or seek further information on this project, please use the details below:

9 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission.

10 For more information see https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3.

11 For more information see https://www.aemc.gov.au/contact-us/lodge-submission.

- **Project leader:** Shannon Culic
- **Email:** shannon.culic@aemc.gov.au
- **Telephone:** (02) 8296 1640

1.5 Consultation continues following receipt of submissions

The Commission is committed to continuing to engage collaboratively with stakeholders and market bodies in developing the proposed options. Following receipt of submissions, we will:

- reconvene the project technical working group (TWG) in Q3 2023 to seek feedback on the way forward to input into the development of the draft determination
- publish a draft determination in Q3 2023 (and we encourage all interested parties to make a submission following its release)
- publish a final determination following receipt of submissions against the draft determination, aiming for December 2023.

1.6 AEMO provided technical advice on the development and case for an operating reserve market

In December 2021, the AEMC requested that AEMO provide advice on key design elements of an operating reserve service to support the consideration of the two rule change requests. The AEMC requested that AEMO develop this advice based on a 'working model' of an operating reserve market as set out in the request for technical advice.[12]

In November 2022, AEMO submitted its technical advice to the AEMC.[13] The AEMC thanks AEMO for its analysis on the design elements of an operating reserve market. This advice has provided significant value to the AEMC in progressing these rule changes further by enhancing the Commission's understanding of the key issues and possible solutions.

AEMO's analysis included advice on the:

- development of an operating reserve demand curve
- implementation of a causer pays cost recovery mechanism for the market
- reserves obligation and interaction with dispatch and other processes
- direct implementation costs and proposed timing of an Operating Reserve market.

The AEMC has considered AEMO's technical advice in the development of this directions paper and discusses it in the relevant sections throughout.

12 For more information see https://www.aemc.gov.au/sites/default/files/2022-01/Correspondence%20re%20Operating%20reserves%20technical%20advice%2023.12.21.pdf

13 AEMO's Technical Advice https://www.aemc.gov.au/sites/default/files/2022-01/Correspondence%20re%20Operating%20reserves%20technical%20advice%2023.12.21.pdf.

2 RESERVES IN THE POWER SYSTEM

BOX 1: KEY POINTS IN THIS CHAPTER

- Reliability means that the power system has an adequate amount of capacity (generation, demand response and network capacity) to meet consumer needs. Reliability is delivered in the NEM through investment, retirement and operational decisions made by market participants, informed by data including that provided by AEMO and a set of reliability settings and standards. The framework is supplemented by a series of mechanisms that allow the system operator to intervene in the market in specific circumstances in order to maintain a reliable supply to customers.
- A key component of the system is e*nergy reserves ('reserves')*, which are capacity that is not currently used to supply energy to meet demand, but is available and capable of changing to maintain the energy supply/demand balance in the near future.
- Currently the NEM has reserves that are both in-market and out-of-market. In-market reserves are those that are available for dispatch on the basis of their market offers, while out-of-market reserves are procured and dispatched by AEMO as a last resort to prevent load shedding.
- Participants currently submit information to AEMO, with AEMO then using a range of forecasting tools to identify and communicate supply/demand imbalances and potential future reserves needs to market participants. AEMO forecasts reliability on a number of timescales in advance of real-time through its PASA process.
- Market participants rely on information provided by AEMO to respond to potential supply/demand imbalances. Participants make unit commitment decisions ahead of time that collectively determine the capacity available to be dispatched in real-time using this information.
- If AEMO considers that the market has not responded, or will not respond, to published information by making sufficient reserves available, it may use a range of tools to intervene in or act out of the market, to avoid load shedding.

2.1 Energy reserves are not explicitly priced under current arrangements

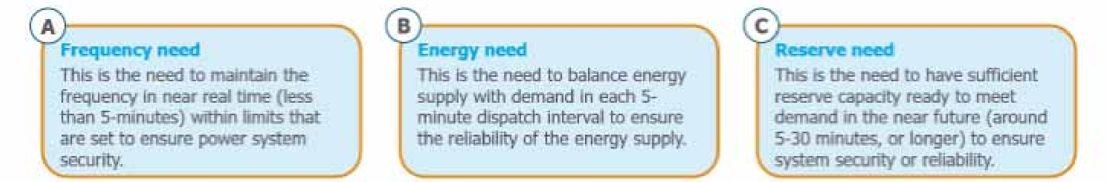
The power system is designed to be *reliable* and to be *secure*:

- The system is *reliable* when there is an adequate amount of capacity (generation, demand response and network capacity) to supply consumers with the energy they demand with a very high degree of confidence.
- The system is *secure* when technical parameters such as voltage and frequency are maintained within defined limits. This means that after being faced with sudden shocks or events, the system remains stable, and can return promptly to a state where it can

handle further shocks. A secure power system is designed to withstand a single credible contingency event, which is an event that AEMO expects would likely involve the failure or removal from operational service of one or more energy-producing units, facilities and/or network elements; or an unplanned change in load.

A reliable and secure power system seeks to balance supply and demand instantaneously (or, at least very near real time) such that the frequency of the power system is maintained within limits and energy is delivered to customers consistent with what they demand. This is achieved by meeting three practical power system needs that relate to controlling active power on the system, illustrated in Figure 2.1.[14]

Figure 2.1: Power system need for active power control



Source: AEMC

A reliable and secure power system needs enough resources to meet each of these needs, accounting for uncertainty and variability as the characteristics and needs of the system change. To date, each of these needs has been met by arrangements as set out below.

2.1.1 Frequency needs

In an operating power system, the frequency varies whenever the supply from generation does not precisely match customer demand. Whenever total generation is higher than total energy consumption the system frequency will rise and vice versa. Controlling frequency is critically important to maintaining a secure and reliable power system.[15]

To maintain a stable system frequency, the supply of electricity into the power system must balance the instantaneous consumption of electricity at all times. AEMO operates the wholesale electricity market, which dispatches electricity generation, to meet the expected demand for electricity every five minutes. Some imbalance between supply and demand is expected to occur within the five-minute dispatch process; these imbalances are managed through a market for regulation FCAS.

AEMO coordinates the FCAS markets, which enables resources to be increased or decreased at short notice to restore the power system balance. The FCAS markets include:

14 There are two components of AC electric power, active power that does actual work (i.e. provides heat, light and motion), and reactive power that enables the transport of electrical current.

15 Further detail on the importance of frequency can be found in Appendix B and C of the Reliability Panel's Issue Paper on the *Frequency Operating Standard*, https://www.aemc.gov.au/sites/default/files/2022-04/rel0084_-_review_of_the_fos_-_issues_paper.pdf.

- the procurement of regulating raise and lower services that are managed through AEMO's automatic generation control system that continuously monitors the power system frequency and sends out "raise" or "lower" signals to the registered generators and loads that are dispatched to provide FCAS to correct small frequency deviations
- the procurement of contingency services that provide AEMO with the ability to manage the power system frequency in response to the single failure of a single generating unit or major transmission element (a 'credible contingency event'). Contingency FCAS is divided into raise and lower services at six different speeds of response and sustain time.[16]

In the event that insufficient FCAS is available to manage the risk of a credible contingency event, AEMO may use other means to maintain the secure operation of the power system e.g. pre-emptive constraining of interconnector flows and/or generation output to reduce the size of the possible contingency event. AEMO also coordinates a range of emergency frequency control schemes to address more substantial frequency deviations that results from more severe contingency events. These schemes operate to rapidly disconnect load or generation in order to re-balance the power system and restore the frequency.

2.1.2 Energy needs

The NEM's spot market is a gross pool design with mandatory participation. Generators sell, and market customers buy, all of their electricity through the spot market, which matches supply and demand (near) instantaneously, including an allowance for a sufficient quantity of reserves. Reserves in the NEM are represented by those generators that offer their availability into the wholesale market, but are not dispatched.

Scheduled and semi-scheduled generators and loads offer and bid into the market dispatch engine, operated by AEMO. Once these offers and bids are received, AEMO then forecasts the expected consumer demand for electricity in each region for each five-minute dispatch interval. Then, the dispatch engine seeks to optimise outcomes by attempting to maximise the value of trade given the physical limitations of the power system. These physical limits are otherwise known as "constraints" which reflect technical limitations of the system, for example, restricting how much electricity can flow over a particular piece of equipment to make sure it is kept within its technical capability.

The market settings — the reliability standard, the market price cap, cumulative price threshold, administered price cap and market floor price — are an integral part of the reliability framework. They limit the extent to which wholesale prices can rise and fall. They are set at a level so as not to interfere with the price signals needed for efficient investment and operation.

A key role of the reliability standard is to guide various decisions made by AEMO in its role as system operator, with these decisions then provided as information to the market, informing market participant decision-making. It is AEMO's responsibility to incorporate the reliability standard within its day-to-day operation of the market and to inform the market of any

16 Two new fast frequency response markets will also be introduced in October 2023.

projection that the reliability standard will not be met. If market participants do not respond to an expectation from AEMO that the reliability standard will not be met, then AEMO may intervene through either one of its intervention tools.

Market participants submit the price and quantity of electricity they are willing to generate to AEMO in advance of real-time and can re-bid their offers should information or conditions change. Therefore, participants have an incentive to maintain reserves to take advantage of more timely information.

2.1.3 Reserve needs

In the NEM there are both in-market and out-of-market reserves:

- In-market reserves are determined by AEMO based on information provided by market participants. Reserves considered in-market are made up of capacity that is offered by market participants into the energy markets as being 'available' but which is not dispatched. This energy has the potential to be dispatched in response to changes in supply and demand. As discussed, AEMO provides operational information to the market about whether there are projections of sufficient capacity to meet demand to help prompt participants to offer more supply if there is a projected shortfall. Participants also consider market and weather conditions, as well as their own costs and financial position, when making themselves available. This is discussed in further detail in section 2.6. Market participants make their own commitment decisions to keep capacity in reserve based on price signals and operational costs associated with generating energy at a particular point in time.
- Out-of-market reserves are procured by AEMO. AEMO can procure out-of-market reserves if forecast reliability is projected to be outside the relevant standard (discussed more below). If AEMO considers that the market has not or will not respond (with in-market reserves) to fill a reserve shortage, it can intervene to provide additional, out-of-market reserves. Out-of-market reserves are procured and then dispatched if required by AEMO. Typical examples of out-of-market reserve that can be procured for RERT include unscheduled load that can be curtailed and restored on request from AEMO, and unscheduled generation assets. Such out-of-market reserve assets must not be available to the wholesale market through any other contract or arrangements in the trading intervals in which the reserve is required. This is intended to be used as a last-resort mechanism. RERT is discussed further in section 2.5.

2.1.4 Operating reserves support system reliability and security

As AEMO set out in its technical advice, 'operating reserve' is defined as the capability to respond to large continuing changes in energy requirements.[17] Minimum levels of operating reserve are required for the system operator to maintain system security and reliability. Operating reserve, or 'headroom' can be measured in pre-dispatch and other systems as offers of energy above forecast demand. If the supply-demand balance tightens compared to

17 AEMO's Technical Advice https://www.aemc.gov.au/sites/default/files/2023-06/Powerlink%20submission%20June%202023.pdf.

its forecast, operating reserves can be dispatched as energy. Operating reserves are headroom that can be utilised over time horizons beyond a single dispatch interval.[18]

As set out above, the reserves currently in the NEM largely come from incentives in the energy spot market, participant positioning to manage individual financial risks, and as a by-product of the technologies comprising the generation fleet.

2.2 Reliability settings underpin market participant reserve decisions

The **reliability standard** expresses the desired level of reliability sought from generation assets, demand response, and the transmission lines that transport power between states. The reliability standard is an expression of the efficient level of unserved energy in the NEM based on what consumers are willing to pay.[19]

It underpins the operational and investment decisions that drive reliability. Set in the NER, the standard is expressed as the maximum expected unmet demand (i.e., unserved energy) for each financial year, as a proportion of the total demand in that region.

The current reliability standard (0.002 per cent expected unserved energy in a region per financial year) requires that supply matches demand at least 99.998 per cent of the time in every region each financial year.[20] To uphold this, the expected level of supply needs to include a buffer (in-market reserves) to limit the amount of unserved energy occurring given potential contingencies and unexpected events such that expected supply is greater than expected demand.

The reliability standard is currently expressed as an expected value (average) of a probabilistically determined distribution of possible unserved energy outcomes. The Reliability Panel has commenced a review of the form of the standard in recognition of a shifting reliability risk profile as the NEM transitions from a capacity-limited thermal power system to a high variable renewable energy (VRE) and more energy-limited power system. It is considering whether a single expected value provides sufficient information to inform the development of reliability frameworks that are fit for purpose in a future NEM.

Other related metrics include the **interim reliability measure** (**IRM**) and the **retailer reliability obligation** (**RRO**).

The IRM has been introduced to set out a tighter standard, such that the expected unserved energy in a region per financial year is 0.0006 per cent.[21] The aim of the RRO is to provide stronger incentives for market participants to invest in the right technologies in regions where it is needed.[22] The IRM is used to trigger the RRO and sets the threshold where AEMO can procure interim reliability reserves.

18 AEMO's Technical Advice https://www.aemc.gov.au/sites/default/files/2023-06/Powerlink%20submission%20June%202023.pdf.

19 Values of customer reliability (VCR) play an important role in helping consumers pay no more than necessary for safe and reliable energy, helping energy businesses identify the right level of investment to deliver reliable energy services to customers.

20 AEMC, 2020, The Reliability Standard, https://www.aemc.gov.au/sites/default/files/2020-03/Reliability%20Standard%20Factsheet.pdf.

21 AEMO, 2020, RERT, https://aemo.com.au/-/media/files/learn/fact-sheets/rert-fact-sheet-2020.pdf.

22 AEMC, 2023, Review of the retailer reliability obligation, https://www.aemc.gov.au/market-reviews-advice/review-retailer-reliability-obligation.

The market price settings set the wholesale market price parameters, specifically:

- *market price cap* — the maximum price that can be reached on the spot market during any dispatch and trading interval
- *cumulative price threshold* — the value of cumulative five-minute prices that, if breached, triggers an administered pricing period
- *market floor price* — a price floor applied to spot prices in the wholesale energy market
- *administered price cap* — the price at which the spot price is capped in the NEM, following a prolonged period of extreme prices (when the *cumulative price threshold* is breached).

The price settings are established at levels sufficient to provide enough revenue potential for new entrants, but not so high as to create systemic financial risks which could compromise the stability of the market. These settings are under review as part of a rule change request that the AEMC is currently considering.[23]

2.3 AEMO supports participant reserve decisions through forecasting tools

It is AEMO's responsibility to determine the level of reserves required in planning and operational timeframes to uphold the reliability standard using forecasting tools. AEMO therefore operationalises the reliability standard through its forecasting processes, which provide information to market participants and potential investors.[24] These include publishing energy market outlook reports such as the Integrated System Plan (ISP) and the Electricity Statement of Opportunities (ESOO) and using the Projected Assessment of System Adequacy (PASA) process to forecast the overall supply/demand balance for electricity over various time periods.

These tools are highlighted in Figure 2.2.

Figure 2.2: Timeline of forecast information provision

Source: AEMC

23 For more information see https://www.aemc.gov.au/news-centre/media-releases/examining-suitability-reliability-framework-aemc-initiates-rule-change-process

24 Clause 4.8.4A of the NER.

2.3.1 The ISP and ESOO inform long-term capacity investment decisions

The ISP and ESOO are energy market outlook reports published by AEMO to inform long-term investment by market participants in technologies that will fill forecasted shortfalls in capacity:

- The ISP provides a whole of system plan to guide investment that secures an affordable, secure, and reliable power system while meeting emissions reduction scenarios over a 20-year timeframe.
- The ESOO forecasts electricity supply reliability over a 10-year timeframe, including an assessment against the reliability standard, as well as for the interim reliability measures for the purpose of the RRO.

2.3.2 PASA provides information to market participants in relation to expectations for operational timeframes

The PASA predicts supply constraints over shorter timeframes, based on the reliability standard. It considers AEMO's load forecasts, reserve requirements (to uphold the reliability standard) and network constraint information. These are balanced against participant inputs (offers) relating to unit capacity and energy availability. It is forecast over three time periods:

- **Medium Term (MT) PASA** covers a two-year horizon and is produced weekly.[25]
- **Short Term (ST) PASA** covers 6 trading days (i.e., each day for the period two to seven days ahead). The calculation of the ST PASA is run every two hours.[26]
- **Pre-dispatch (PD) PASA** covers one day (i.e., forecast each day for the day ahead).

AEMO uses the PASA process to calculate the level of reserve capacity by forecasting the regional excess supply (RXS) for a region for each five-minute trading interval against the reliability standard. This forecast is based on:

- the aggregate capacity of scheduled generation (aggregate non-energy limited capacity, plus aggregate energy limited capacity, minus aggregate semi-scheduled capacity), plus
- interconnector support, plus
- forecast aggregate semi-scheduled availability, minus
- scheduled demand.[27]

An uncertainty factor (known as the forecast uncertainty measure (FUM)) is then generated using RXS error distributions, which considers historical forecasted RXS minus actual RXS for various prevailing weather and generation mix scenarios.[28]

25 AEMO, Medium term PASA process description, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/projected-assessment-of-system-adequacy, p. 19.

26 AEMO, Short term PASA process description, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/projected-assessment-of-system-adequacy, p. 8. Under ST PASA requirements, generators are obliged to submit a range of inputs including maximum plant availability 'under expected market conditions' (clause 3.7.3e of the NER. This capacity can be commercially withdrawn from the market based on individual expectations of future opportunities.

27 Applicable to NSW, QLD, SA and Victorian regions. RXS for Tasmania excludes components which are affected by a requirement to export due to network constraints.

28 AEMO, Reserve level declaration guidelines, https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/reserve-level-declaration-guidelines.pdf, pp. 7-8

There is also currently work underway to review and revise the PD PASA and ST PASA with AEMC making recent rule changes around ST PASA, which is discussed further in chapter 5.

2.3.3 Five-minute dispatch provides the market with the nearest-term projection of the demand target

AEMO determines the electricity demand target in five-minute intervals and communicates this with market participants via the Electricity Market Management System (EMMS). AEMO's central dispatch engine, the national electricity market dispatch engine (NEMDE) orders generator offers of price and quantity of electricity from least to most expensive and determines which generators will be dispatched. Its objective is to dispatch the lowest-cost mix of generators to meet expected demand.

Prior to October 2021, prices were settled every 30 minutes to form a wholesale market ('spot') price, determined as the average of the previous six, five-minute dispatch prices.[29] Since October 2021, five-minute settlement has been in place, aligning operational dispatch and financial settlement at five-minute intervals.[30]

Five-minute dispatch provides stronger financial incentives for generators to quickly respond to changing demand conditions than under 30-minute settlement. This likewise provides a stronger financial incentive for investment in flexible resources required in a NEM with more variable net demand conditions. Early five-minute settlement observations indicate improved plant responsiveness on a five-minute-by-five-minute basis and improved investment cases for fast-start plant.

2.4 Communicating with market participants when reserves are needed

AEMO uses the PASA process to identify whether a reserve shortfall is forecast and will communicate this reserve need through a lack of reserve (LOR) notice.

2.4.1 LOR conditions signal to the market a reserve need

LOR notices are published to elicit a market response to address a possible reliability issue prior to AEMO intervening in the market to maintain reliability. AEMO declares LOR notices considering the amount of capacity that could be lost in the largest credible contingencies (forced generator or network element outage) as well as the amount of capacity at risk associated with demand and variable renewable generation uncertainty which can become large given weather variability. AEMO uses the forecast uncertainty measure (FUM) to assess the capacity at risk due to forecast uncertainty.[31] LOR condition notices are issued in three

29 AEMC, How power is dispatched across the system, https://www.aemc.gov.au/energy-system/electricity/electricity-market/how-power-dispatched-across-system.

30 AEMC, Rule determination national electricity amendment (five minute settlement) rule 2017, https://www.aemc.gov.au/sites/default/files/content/97d09813-a07c-49c3-9c55-288baf8936af/ERC0201-Five-Minute-Settlement-Final-Determination.PDF.

31 The FUM introduces a probabilistic element into the determination of LOR levels alongside the traditional deterministic approach which allows for the impact of estimated reserve forecasting uncertainty in the prevailing conditions when calculating the LOR levels. These estimates are made on the basis of modelling past reserve forecasting performance for demand, output of intermittent generation and availability of scheduled generation.

levels (LOR 1, LOR 2 and LOR 3) based on the urgency of the reserve need and are communicated to the market through market notices:

- **Lack of reserves 1 (LOR 1)** — actual and forecast LOR 1 conditions are declared to elicit a market response when forecast or actual reserves fall below the larger value of either the FUM or the two largest contingencies in the region.
- **Lack of reserves 2 (LOR 2)** — occurs when forecast reserve falls below the larger value of either the FUM or the largest credible contingency in the region.
- **Lack of reserves 3 (LOR 3)** — when actual or forecast capacity reserves are below zero indicating load shedding is forecast or actually occurring.

As part of this framework, AEMO will inform market participants if a shortfall in supply is forecast. Market participants will be informed by AEMO of the LOR conditions through market notices. If a reserve shortfall is identified within the:

- ST PASA forecast (i.e., the period 2 to 7 days ahead), AEMO will issue a market notice advising forecast LOR 1 conditions only if they appear in the PASA calculation run completed at 1400hrs (2 pm AEST). LOR 2 will be declared as soon as possible after being identified.
- PD PASA forecast (i.e., within the next trading day), AEMO will issue a market notice advising forecast LOR conditions if any LOR conditions (LOR 1/LOR 2/LOR 3) are present in the current pre-dispatch period (i.e., the next trading day).[32]

These notices provide information to market participants that inform their expectations of prices in the energy market. Market participants may respond to this information by making their capacity available (i.e., as reserves) to the market.

If AEMO considers that the market has not responded to published information by making sufficient reserves available as part of normal market operation, it may use a range of tools to intervene in, or act out of, the market.

2.5 Market intervention mechanisms are available to AEMO

In operational timeframes, AEMO observes the market's response to LOR notices and allows the market to take its course up until the "latest time to intervene", which they estimate and publish when the LOR notice is released.[33]

If the latest time to intervene has passed and the market has not provided sufficient additional reserves to address the shortages projected in the ST and/or PD PASA, AEMO may intervene with directions, instructions,[34] and/or RERT contracts.

32 AEMO, Short term reserve management, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3703-short-term-reserve-management.pdf, pp. 5-6. AEMO may update or cancel the LOR conditions within the 1400hr ST PASA forecast period of more recent pre-dispatch schedule.

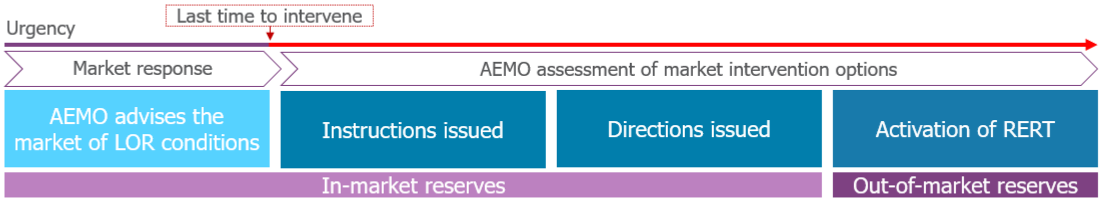
33 In accordance with Clause 4.8.5A and 4.8.5B of the NER. For example, Reserve Notice 72883 published on 23/01/2020 at 11:16:35 AM forecasted LOR2 conditions from 1530 hrs to 1730 hrs the same day. The last time to intervene was 1330 hrs that day (At 11:22:50 AM, AEMO published an intention to commence RERT contract negotiations).

34 Instructions are issued in accordance with Clause 4.8.9 of the NER.

AEMO intervention is a last resort mechanism to maintain the system in a reliable state, and avoid load shedding.

The level to which AEMO intervenes in the market is dependent on the response of market participants to the information supplied within the operational timeframe. Figure 2.3 provides an overview of the intervention mechanisms available to AEMO.

Figure 2.3: Intervention mechanisms in place



Source: AEMC

The three intervention mechanisms operate as follows:

- **Directions** are issued to registered participants (generators and scheduled loads) to operate at a specified output or consumption level and are dispatched through normal market processes. Generators are compensated for responding to the direction. Issuing directions for reliability reasons is rare, given that market prices are typically high at such times incentivising available generators to commit for dispatch.
- **Instructions** are final resort notices to Network Service Providers (NSPs) to load-shed customers to maintain the integrity of the power system. AEMO will consider the cost of lost load and any material distortionary effects and assess the amount of the user's load available to shed, key network locations and load shedding procedures before issuing instructions. Instructing networks to shed load is rare. Under manual load shedding a limited number of customers experience load shedding for a short period (generally on a rotational basis), with each state and territory having a plan for how load shedding is to be carried out.
- **RERT** where AEMO secures availability of emergency out-of-market reserves through contracts from providers which can be activated (or pre-activated) upon request. RERT is described further below.

RERT includes generation or demand response that is not otherwise available in the market. RERT reserves are contracted in addition to the reserve buffer that is already made available by the market (and assessed via PASA processes) as part of the market's usual operation. The operation of the RERT is divided into two stages to firstly procure and secondly dispatch or activate reserves.

The RERT guidelines specify three types of RERT based on how much time AEMO has in which to procure the RERT prior to the projected reserve shortfall occurring:

- **Long-notice RERT** — At least ten weeks' notice of a projected reserve shortfall

- **Medium-notice RERT** — Between one and ten weeks' notice of a projected reserve shortfall
- **Short-notice RERT** — Between three hours and seven days' notice of a projected reserve shortfall.

Interim reliability reserve contracts can be signed for a period of three years when AEMO identifies a reliability gap against the IRM in the ESOO.[35] See appendix A for further information on RERT.

2.6 Price signals incentivise in-market reserves

As discussed above, energy price signals provide the primary incentive for parties to supply the required energy to match demand in real-time.

The contracts market that sits outside formal energy market arrangements also provides important incentives for generators to make themselves available to the market in a way that supports reliability. In the short term, generators that have sold contracts are incentivised to be available when needed (i.e., when spot prices are high) in order to be dispatched to at least their contracted level to fund payouts on contract positions. Generators who are not available to defend contracted positions face a significant financial penalty given the difference between contract strike prices and the market price cap at $16,600/MWh. This incentive to commit and provide capacity and reserves is the strongest during periods when reliability is most compromised, and so prices are high. The incentive of high prices also secures the provision of in-market reserves, as market participants manage their ability to respond to changing market conditions, and so more participants make themselves available in anticipation of these high prices being realised.

For market participants, there can be costs associated with being ready to generate or provide a demand-side response. As an example, thermal generators have start-up costs, which are incurred on each occasion they commit their plant for dispatch. Participants must therefore consider whether it is worthwhile making their capacity ready (i.e. providing reserves), which is determined based on the assessment and risk appetite of that participant given potential revenues from dispatch.

2.7 Reserves help manage both expected and unexpected events

Market participants respond to price signals and other market information, including AEMO notices, based on their own expectations of what the market will do and whether any forecast shortfalls will actually materialise. Events that may give rise to a reserves need can be characterised as 'expected' or 'unexpected':

- **Expected events** are those that can be readily predicted by market participants. Examples of expected events include evening ramping requirements and peak consumer demand events that are relatively close to the net demand needs signalled to market participants by pre-dispatch information (noting net demand includes total consumer

35 Clause 11.128.4 of the NER.

demand less distributed energy resources (DER), such as residential solar PV, and VRE generation).

- In contrast, **unexpected events** are not readily forecast or predicted ahead of time. Examples include instances where net demand needs vary (possibly significantly) from what was signalled to market participants by pre-dispatch information. That is, changes in net demand that occur without sufficient time for updated information to have a material impact on the levels of reserve that are available to help balance the energy market in the near future. This may include a contingency-type event for which the LOR framework is specifically designed, but also unexpected changes in net demand due to uncertainty in battery charge, availability of participants, forecasting of VRE generation (e.g., an unexpected drop in wind or solar output over a five-30 minute period).

Expected and unexpected events can manifest as 'forecast errors'. Forecast errors are the difference between the forecast and actual outcome on the power system. The further out from real-time the forecast is made, the greater the extent of the error. Therefore, the forecast error is generally stated on a specific timeframe, for example '30 min forecast error' is the difference between the forecast 30 min ahead and the actual outcome.

Two key terms in this context are:

- **Operational demand error** is the forecast error in the demand to be met by scheduled, semi-scheduled and non-scheduled generators with capacity greater than 30MW. Operational demand does not include demand that is met by distributed PV (i.e. rooftop solar). Accordingly, forecasts of operational demand must forecast the impact of distributed PV. Therefore, errors in rooftop solar forecasting do impact operational demand forecast errors, but large scale VRE forecast errors do not.
- **VRE forecast error** is the sum of errors in the forecast output of semi-scheduled and non-scheduled VRE generation. This does not include errors in distributed PV forecast output.

As outlined in section 2.4.1 the FUM introduces a probabilistic element into the determination of LOR levels alongside the traditional deterministic approach which allows for the impact of estimated reserve forecasting uncertainty in the prevailing conditions when calculating the LOR levels. These estimates are made on the basis of modelling past reserve forecasting performance for demand, output of intermittent generation and availability of scheduled generation.

2.8 Both flexibility and duration are required to meet reserve needs

The extent to which a shortfall of reserves may arise depends on whether the flexible/scheduled capacity in the system is committed and positioned appropriately to deal with both the increased variability (greater variations observed in the supply/demand balance) and uncertainty (unexpected net demand ramps).

BOX 2: FLEXIBILITY AND DURATION

Flexibility is the extent to which a type of capacity's output can be adjusted or committed in or out of service. This includes the speed of response to start up and shut down, rate of ramping, and whether it can operate in the full range of capability, or has restrictions (such as minimum generation requirements, or other limitations).

Duration is the ability to sustain a response over extended periods (for example, over hours), influenced by fuel reserves or storage capacity.

There are two key timeframes that are relevant to the optimal delivery of reserves, especially with increasing VRE generation, batteries and flexible load on the power system. These are:

- relatively short timeframes (e.g. five minutes to one hour), where the flexibility of in-market reserves (ramping and headroom) is important (**flexibility**), and
- over the course of the day, where the **duration** of reserves (energy in MWh) that can meet energy needs is important.[36]

The overall ability of supply on the system to balance demand in operational timeframes is ultimately dependent on the availability of headroom[37] for online scheduled capacity and interconnection, as well as the availability of fast-start units and how quickly they can start and ramp up. Headroom refers to the capacity for a generator or battery to raise their output in response to increased demand. This means that, in investment timeframes, the reliability of the power system also hinges on the flexible and fast start capacity on the ground.

2.9 Price signals also drive investment decisions

These same price signals that incentivise participants to provide in-market reserves, drive participant investment decisions. High prices for reserves incentivise investment in the kinds of plant that can make reserves available to capitalise on those prices. The contract market provides a forward signal of wholesale prices, again encouraging participants to invest when prices are high.

Many jurisdictions now have in place additional schemes to further encourage investment in flexible plant. For example, the NSW Electricity Roadmap is a 20-year plan to transform the NSW electricity system into one that is cheap, clean and reliable. The Roadmap is enabled by the Electricity Infrastructure Investment Act 2020, and seeks to support the private sector to deliver at least 12 GW of new renewable electricity generation, and 2 GW of long duration storage, such as pumped hydro. In addition to jurisdictional schemes, the Commonwealth,

36 The power system requires energy reserves to be capable of being dispatched by the NEMDE every five-minutes, on an ongoing basis. Reserves are therefore required to be capable of becoming energy across all forward timeframes.

37 It is dependent on the generating level of the plant based on market dispatch along with energy source availability and plant operating limits. Unless curtailed due to system constraints, semi-scheduled generators such as solar and wind power stations typically do not maintain stored energy or headroom, as their generation output is limited by the energy availability of the wind or sun. On the other hand, scheduled generators including thermal, hydro and batteries typically operate with some level of stored energy availability which varies by plant type. Scheduled generators maintain stored energy for a range of reasons, including maintaining a minimum ramp rate capability and in accordance with being enabled in the market for provision of frequency control ancillary services.

state and territory ministers agreed in principle to establish the Capacity Investment Scheme (CIS).

> The Department of Climate Change, Energy, the Environment and Water describe the CIS as a "national framework to drive new renewable dispatchable capacity. This will ensure reliability in the rapidly changing energy market into the future. This new revenue underwriting mechanism will unlock $10 billion of investment in clean dispatchable power".[38]

Over the long-term, the CIS will seek to provide market participants incentives to enable adequate capacity dispatchable capacity to be available to meet future energy demand.

38 Department of Climate change, Energy, the Environment and Water. Capacity investment scheme to power Australian energy market transformation, https://www.energy.gov.au/news-media/news/capacity-investment-scheme-power-australian-energy-market-transformation

3 THE INCREASING NEED FOR RESERVES AS THE POWER SYSTEM TRANSITIONS

BOX 3: KEY POINTS IN THIS CHAPTER

- The rule change requests discuss the issue of increasing variability and uncertainty in power system conditions, driven by the transition to greater penetrations of VRE generation. The outcome of this issue is an increased requirement for energy reserves on the power system to respond to changes in the supply/demand balance in operational timeframes.
- The AEMC has considered this and agrees with the rule change proponents that there is increasing variability and uncertainty due to the transition.
- However, in our assessment, the issue is likely transitional. While variability and uncertainty may increase across the transition, in the longer-term this is expected to moderate.
- This is because as the transition proceeds, we expect to see increasing technological and geographic diversity of VRE generation and storage, as well as potential improvements in forecasting capabilities. These trends can serve to limit the frequency and impact of unexpected events and therefore to moderate variability and uncertainty in power system conditions.
- The increased need for reserves will therefore likely be temporary and confined to the period of the transition.

3.1 The issues raised by the rule change requests and AEMO

The NEM's physical and market reliability risk profile is undergoing a shift:

- The physical reliability risk profile is shifting as the NEM transitions from being a capacity-limited thermal power system to being a weather-driven, energy-limited (both renewables and thermal fuel) power system with declining thermal generation availability.
- The market risk profile has changed as fuel supply arrangements for Australian electricity generation shifted from being domestically focused and insulated from international market pricing and volatility, to being coupled with international markets and exposed to geopolitical event-induced volatility.

The changing risk profile gives rise to an increase in variability and uncertainty in the power system, particularly as more VRE generation is adopted. These issues in the power system have been highlighted in the rule change requests made by Iberdrola and Delta, as well as by AEMO in its technical advice.

3.1.1 Iberdrola suggests current arrangements may not be sufficient to meet the higher risk and frequency of contingency events

In its rule change request, Iberdrola considers that there is a higher risk of contingency events in the future due to more frequent extreme weather events, with such contingency events traditionally not classified as credible.[39] It also considers that there will be 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, Iberdrola highlights that there are decreasing amounts of operating reserves in the system due to transitioning generation stock and a lack of incentives for new investment that has this capability.[40]

3.1.2 Delta highlighted the growing problem of sustained ramping requirements as a result of increased VRE penetration in the NEM

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: [41]

> '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.'

The key problem identified by Delta is that the predictable, daily, high rates of change from solar can lead to increased price volatility, leading to greater variability and uncertainty and therefore 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.

3.1.3 AEMO's technical advice suggests variability and uncertainty are likely to increase

In its technical advice provided to the AEMC, AEMO suggests that forecast uncertainty is expected to increase in the future power system, driven by growing VRE penetration, weather, participant availability, storage depth, and other causes. AEMO notes in its technical advice that it is already witnessing increased variability, uncertainty, and lack of headroom, and an asymmetry of risk between participants and the system operator in carrying out its

39 Iberdrola, 2020, Operating reserves and fast frequency response rule change, https://www.aemc.gov.au/sites/default/files/2020-03/ERC0295%20Rule%20change%20request.pdf, p. 6.

40 Iberdrola, 2020, Operating reserves and fast frequency response rule change, https://www.aemc.gov.au/sites/default/files/2020-03/ERC0295%20Rule%20change%20request.pdf, p. 6.

41 Delta Electricity, 2020, Introduction of ramping services, https://www.aemc.gov.au/sites/default/files/2020-06/ERC0307%20Rule%20change%20request%20pending.pdf, p. 6.

role in meeting security and reliability requirements during times of high forecast uncertainty.[42]

3.2 Our assessment of the evidence for these issues

3.2.1 Net demand ramps are becoming steeper

As discussed in chapter 2, ramps are fluctuations in energy supply and demand over a defined period of time. Ramp rate is the speed that a resource can either increase (ramp up) or decrease (ramp down) its supply. An upward VRE ramp sees the net output from all VRE resources increase over an interval, whereas a downward VRE ramp sees the net output from these resources decrease over an interval. The intervals can vary in timescales, e.g. five minutes or an hour.[43]

Reserves are needed to respond to changes in net demand, known as net demand ramps. This refers to the balance between supply and demand which can both increase or decrease over various timeframes.[44] This is because *net demand* is the underlying demand net of VRE generation (i.e. demand that must be met by scheduled generation sources or batteries and not by wind or solar (including utility solar and distributed PV resources)).[45]

Figure 3.1 shows the magnitude of actual five-minute VRE ramps between 2015 and 2019, as well as projections for the magnitude of these ramps in 2025, by technology.[46]

42 AEMO's Technical Advice https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf.

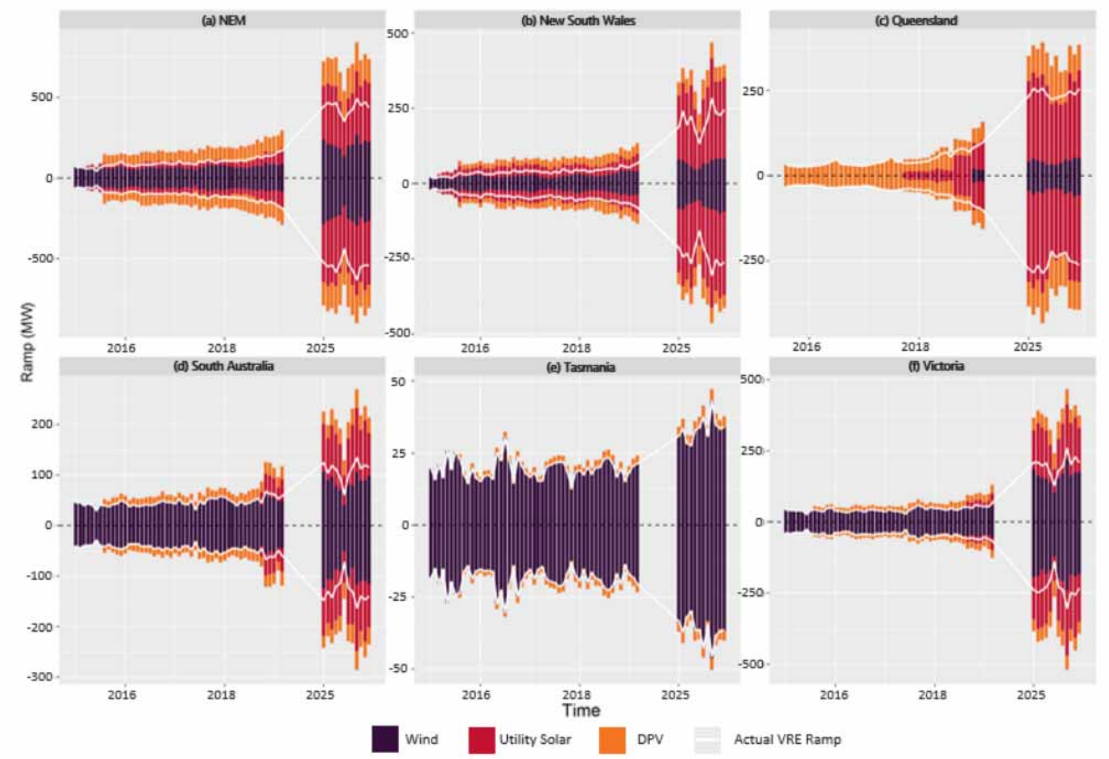
43 Appendix A provides more detail on VRE ramps.

44 Appendix A provides more detail on upward and downward ramps.

45 AEMO, *Renewable integration study stage 1 appendix C: Managing variability and uncertainty,* https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-c.pdfla=en, p. 8.

46 Based on the 2020 ISP Central scenario (which is expected to be exceeded as we are currently tracking above the Step Change scenario).

Figure 3.1: Monthly top 99th percentile upward and downward 5-minute VRE ramps in the NEM



Source: AEMO, Renewable integration study stage 1 appendix C: Managing variability and uncertainty, April 2020, p. 18.

Note: The butterfly plots show the monthly 1st and 99th percentile ramps between 2015 and 2019 and projected for 2025 (calendar years). These are the values that are exceeded in only 1% of cases. The coloured bars are the monthly 99th percentile ramp observed in each region for different VRE types (wind, utility solar and distributed solar). Stacked together they represent the top 1% theoretical ramp for a region if all VRE types had their 99th percentile ramp simultaneously. The white (net ramp) line represents the observed monthly 99th percentile ramp that resulted from the overall coincident movement in wind, solar and distributed solar.

The coloured bars show VRE ramps by technology type (wind, utility solar and distributed PV) while the white line on the graphs track net VRE ramps that are coincident across technologies. The extent of the difference between the white line and the coloured bars depends on the mix of VRE types and the relative geographical diversity in the region. For example, while wind generation in one geographical area may ramp down, utility solar generation in another may ramp up, netting off the effects of the downward wind ramp to produce the VRE ramp that is coincident across technologies. So, while the white line trends up with the growth of installed VRE capacity, the increase shown by the white line is not necessarily proportional to the increase in the theoretical maximum VRE ramp (i.e., if all technologies had their maximum ramp in the same direction at the same time). The more diverse the technologies and geography in a region are, the larger this gap is.

Further, ramps at the 99th percentile have been observed to be increasing following the increase in VRE being installed in the NEM. This trend is projected to continue increasing with more VRE capacity connecting to the NEM into the future, suggesting the *net demand* ramps are becoming steeper over time.

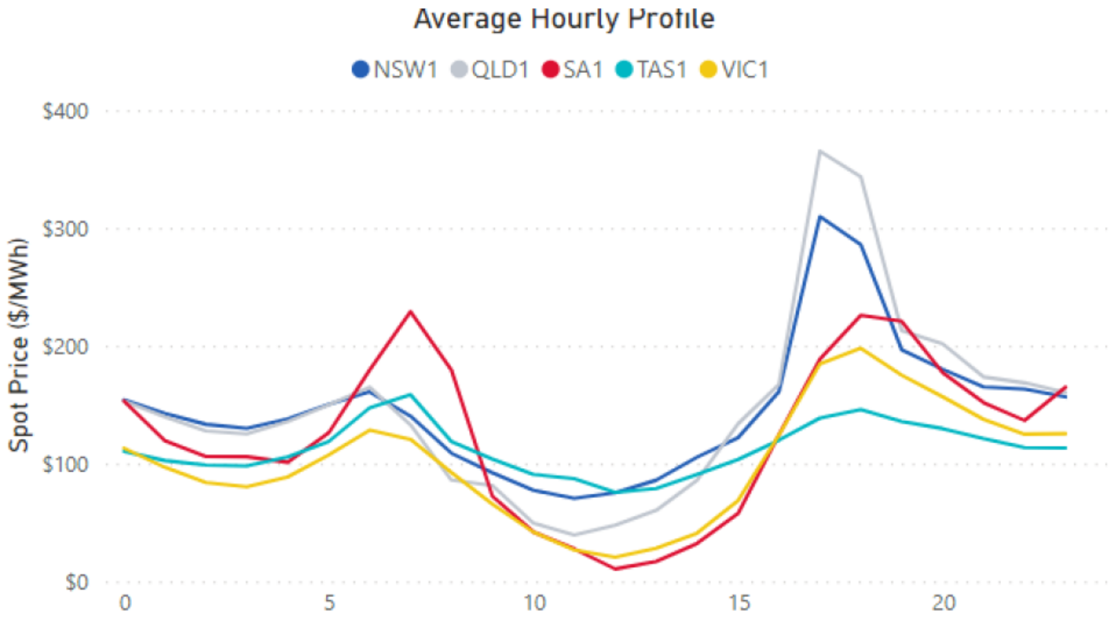
3.2.2 The magnitude of unexpected events in net demand is increasing

The events described above are anticipated to be largely expected, however, of course, there is always likely to be some portion of ramp events that would be unexpected in line with forecasting errors. Forecasting errors will always occur — no one can perfectly forecast the future.

VRE ramps can feasibly occur at any time during the day when weather conditions change. While changes in weather conditions may be forecasted, they may occur at a different time than what was forecasted or to a different size. The extent to which ramping requirements are unexpected by market participants is therefore related to the magnitude of VRE (and net demand) forecast errors that exist in AEMO's forecasting, and the extent to which participants believe these or not.

Let's take for example, the net demand ramp over the evening peak. The Commission considers that the information provided to participants under the current arrangements, outlined in chapter 2, should generally give participants a high degree of certainty that this ramp will occur. Participants will therefore expect a net demand ramp at this time. Prices in the market throughout the expected ramp into the evening peak should reflect the relative scarcity of supply, based on the dispatch of resources through the bid stack. This is demonstrated in Figure 3.2 which shows spot prices typically rising in the early evening from around 4:00 pm, spiking around 5:00 pm before declining just prior to 8:00 pm.

Figure 3.2: Spot prices over the preceding 12 months

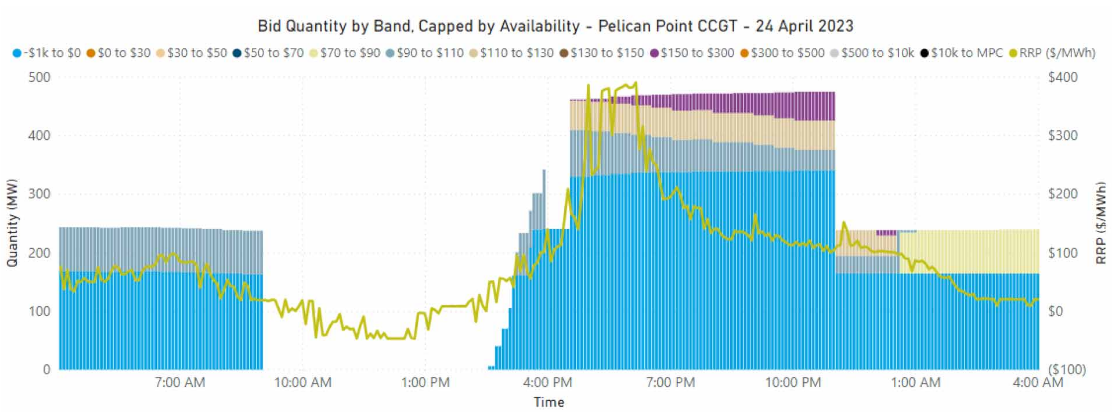


Source: AEMC analysis of AEMO MMS Data
Note: This graph shows average spot prices over a 24-hour period, for the interval 30 June 2022 to 29 June 2023

Participants will understand that such prices are typically higher in the evening ramp period, and so will generally factor this into their operational decisions. They will likely offer in capacity into the market as a 'reserve' that can be called upon and dispatched by NEMDE, because they understand the value that can be earned in this case.

This is illustrated by Figure 3.3 that shows how a unit, in this case Pelican Point, responds to higher evening prices. The graph shows that Pelican Point offers almost all of its capacity in the evening at a low price (-$1,000 to $0) to take advantage of the higher spot prices (the green line).

Figure 3.3: Case study — Pelican Point CCGT responding to high evening spot prices



Source: AEMC analysis of AEMO MMS Data

Note: This graph shows Pelican Point responding to higher spot prices in the evening. Please note, the bids have been capped by availability, e.g. during the middle of the day the bids have set their max availability to zero.

AEMO also points to the energy price incentivising participants to position their fleet to take advantage of higher spot prices noting "to date, operating reserves have been provided in the National Electricity Market (NEM) from incentives in the energy spot market, participant positioning to manage individual financial risks, and as a by-product of the technologies comprising the generation fleet."[47]

Operational demand errors have traditionally been the dominant factor contributing to net demand forecast errors. That is, where the estimate of the level of energy demanded on the system turned out to be incorrect.

However, going forward, VRE forecast errors may be more significant. This is because of the increase in VRE generation capacity on the power system, particularly during the transition. As noted by AEMO "Forecast uncertainty is expected to increase in the future (2025+) power system, contributed to by factors including growing variable renewable energy (VRE) penetrations, weather, participant availability, commitment decisions, storage depth, and

47 AEMO's Technical Advice https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf, p. 3.

coordination of distributed energy resources."[48] In the future, VRE forecast errors may become the dominant source of net demand forecast errors.

3.3 We agree with the issues raised though we expect they will be transitional

The Commission considers that while the issues identified through these rule changes could emerge, if they do they may be temporary and will likely diminish in magnitude following the energy transition.

This is because the NEM of the more distant future (approaching 2050), as it is currently envisaged in AEMO's 2022 ISP *Step Change* scenario[49], is characterised by:

- almost double the electricity delivered to approximately 320 terawatt hours (TWh) per year
- coal-fired generation withdrawing faster than announced, with 60% of capacity withdrawn by 2030
- nine times the utility-scale VRE capacity
- nearly five times the distributed PV capacity, and substantial growth in distributed storage
- 46 GW / 640 GWh (gigawatt hours) of dispatchable storage, including virtual power plants, vehicle-to-grid, utility-scale battery, pumped hydro storage, and other emerging technologies
- 7 GW of existing hydro generation
- 10 GW of gas-fired generation for peak loads and firming
- around 10,000km of additional transmission capacity.[50]

We expect that future market participants, based on the likely characteristics of these technologies, would likely be appropriately positioned to respond to any unexpected events as they occur.

The Commission has not seen any evidence to suggest that expected ramp events would become more 'unexpected' in the future. Current evidence suggests that market participants are behaving in accordance with the market signals to continue managing this variability and uncertainty into the future. Further, the Commission notes that both AEMO's and market participants' forecasting abilities should continue to improve over time with access to more data and analytical tools, potentially providing for stronger predictive modelling capabilities.

To the best of our knowledge, it appears as if the diversity of the VRE fleet will also increase, along with battery and storage technologies. Such a trajectory would likely decrease the impact of any net forecast errors and therefore unexpected events. The greater the

48 AEMO's Technical Advice https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf, p. 3.

49 AEMO's 2022 Integrated System Plan https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf.

50 AEMO's 2022 Integrated System Plan https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf, pp. 9 – 13.

geographical and technological diversity of the fleet, the less likely it would be that multiple VRE assets would be impacted by a particular weather system or event in the same way.

Storage capacity is also expected to increase in the NEM during the transition, which would provide both flexible and enduring support to the power system.

4 ADDRESSING THE INCREASING NEED FOR RESERVES

BOX 4: KEY POINTS IN THIS CHAPTER

- The rule change requests consider that changes are required to the current market arrangements to meet the increasing need for reserves, driven by increases in variability and uncertainty.
- Each request proposes that a version of an explicit 'operating reserve market' should be introduced to meet future reserves needs.
- This raises two questions in relation to the issues identified:
  - The first question is whether the current arrangements are expected to manifest sufficient in-market reserves on the system as the transition proceeds.
  - The second question is whether an explicit operating reserve market would offer performance benefits relative to the current arrangements.
- In relation to the first question, the Commission considers that the current arrangements have efficiently and effectively met the need for reserves up to now, and, importantly, they will likely continue to do so throughout the transition. The existing market arrangements, in our view, are sufficiently flexible to manage the potential for a transitory increase in reserve needs, notwithstanding that there may be some bumps along the road as the transition proceeds.
- The current arrangements place material financial risks on all participants. Market participants' resources and analysis, combined with their incentive to manage risks, should continue to result in the collective commitment of reserves sufficient to meet the physical needs of the system, even as it evolves into the future.
- In relation to the second question, we have assessed the changes proposed by the rule change requests. To support our assessment, we sought technical advice from AEMO on a working model of an operating reserve service which would capture the emphasis of the rule change proposals.
- While it may provide greater visibility of market participants' reserve decisions potentially helping mitigate risks, the Commission considers that an operating reserve would not offer any performance improvements relative to the current arrangements, and would introduce additional costs for customers.
- An operating reserve market is not designed as a tool to provide investment signals and there is a risk that such a market may dilute investment signals, particularly for fast-start plant, given the longer procurement window of such a market. Fast-start and long duration capacity are essential to meet reserve needs into the future, and there is

evidence to suggest that the NEM's generation fleet is evolving in this direction under the current arrangements.

- An operating reserve market is also at odds with the direction of recent reforms, particularly five-minute settlement, which involved moving to stronger financial signals to incentivise investment in fast-start plant.
- In our assessment, an operating reserve market does not promote the long-term interests of consumers, and so we do not propose to implement such a service.
- While the Commission's current direction is to not implement an operating reserve market, AEMO's advice has been important to our considerations.

4.1 The current arrangements can meet reserves needs now and into the future

To date, sufficient reserves have generally been delivered under current market arrangements to manage the level of variability and uncertainty that has been experienced in the NEM. The Commission is not aware of any cases where reserves have not been flexible enough in operational timeframes to account for uncertainties in net demand.[51] Further, we consider that these have been provided efficiently for consumers through these arrangements.

However, it is important to consider not just how well the existing arrangements work in today's environment, but how well these arrangements will meet the needs of the transition. That is, whether or not changes could be required to better manage flexibility and variability into the future. We know that it is very likely that the level of net demand variability and uncertainty will be heightened for a time as the transition proceeds.

The key question to explore, therefore, in relation to the ongoing appropriateness of the current arrangements, is whether they are expected to manifest sufficient in-market reserves on the system as the transition proceeds.

In response to this question, the Commission considers that the current market arrangements will effectively and efficiently manage the risk of the increasing need for reserves throughout the transition.

The remainder of this section outlines the Commission's response to this question in more detail.

As discussed in chapter 3, stakeholders, including AEMO and the rule change proponents, have raised concerns regarding the ability of current arrangements to continue to meet reserve needs. These concerns all relate to a potential breakdown between the real-time

51 We note that there have been instances where the aggregate volume of energy supply has been insufficient to meet demand, and in these instances AEMO has needed to activate RERT. An operating reserve market would not offer any improvement on the current arrangements in responding to such instances, given it would not increase the aggregate quantity of generation capacity in the system.

financial risks in the energy market and how participants respond to those risks by committing reserves, which ultimately meets the physical needs of the system. Drivers of these concerns include:

- at times during the transition the power system may have tight or inflexible overall reserve conditions, particularly if exit, entry, and seasonal operating decisions occur in a disorderly fashion
- forecast uncertainty is expected to increase in the future power system, contributed to by factors including growing variable renewable energy penetrations, weather, participant availability, commitment decisions, storage depth and coordination of consumer energy resources
- the shift toward VRE-driven variability and uncertainty may mean participants are unable to adequately assess the financial risk of price spikes, and so they do not commit sufficient reserves
- increasing times of low (but not negative) prices could result in a failure of participants to commit sufficient reserves
- participants commit flexible resources (such as batteries) into increased evening ramping periods, leaving no flexibility left to account for VRE-driven uncertainty
- increased market price volatility leads to an increase in hedging costs, causing many participants to 'self-hedge' and this could impact the commitment of reserves.

AEMO's technical advice notes that it is difficult to predict whether the fleet and market will supply sufficient capability to respond to large continuing changes in energy requirements to avoid frequent AEMO intervention in future. AEMO goes on to note that it is further unclear if the contract market will continue to drive commitment of resources, and in turn mitigate risk for the system operator at times of forecast uncertainty.[52] The AEMC acknowledges this view by AEMO, but as set out below in section 4.1.5 considers that our modelling of the future power system suggests that it will continue to drive commitment. The AEMC is interested in stakeholder views on this.

4.1.1 The provision of reserves is largely decentralised under current arrangements

As discussed in chapter 2, under the current market arrangements, market participants make their own commitment decisions to keep capacity in reserve based on:

- price signals in the energy and ancillary service markets, as well as associated financial products via contract and spot markets
- the operational costs associated with running their generating plant at a particular point in time.

Provision of reserves is decentralised — that is, the total quantum of reserves available is based on the individual decisions of market participants.

52 AEMO's Technical Advice https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf.

The reliability framework aligns the risks on market participants with the reliability needs of the power system, over both operational and investment timeframes.

A decentralised approach places strong financial discipline on all participants to manage their risks. The collective resources available to market participants to manage financial risks are likely to result in sophisticated analysis of the risks and the potential costs and benefits of different courses of action.

4.1.2 Market participants face financial risks to make reserves available

The allocation of financial risks to retailers is the principal mechanism underpinning the ability of the current energy market framework to meet the system's need for reserves into the future, even with new drivers of variability and uncertainty as technologies change.

The risks are high and need to be managed. Retailers will either shift that risk to another party (i.e. a generator) through contracting or will seek to manage that risk themselves through vertical integration and scheduling their own physical capacity on the system. Regardless of which is the case, the risk is allocated to the party best able to manage that risk through the physical commitment of reserves on the system. Box 5 provides an example of how an individual market participant's risk management decisions manifest in-market reserves in the NEM.

BOX 5: EXAMPLE OF HOW FINANCIAL RISKS MANIFEST RESERVES ON THE SYSTEM

Consider the example of a generator that has a marginal cost of $50/MWh and has sold a 200 MW swap at $100/MWh. Suppose that the generator takes four hours to start up but once started can ramp at 100 MW/hour. The NEM spot price is low at $10/MWh because it's the middle of the day with good solar output. Then there is an un-forecast shock which causes a 1,000 MW reduction in solar output, and the spot price jumps rapidly from $10/MWh to $15,000/MWh.

Consider the case where the generator is switched off at the time of the price spike, because the prevailing spot price of $10/MWh is below its short run marginal cost of $50/MWh and it cannot foresee the upcoming price spike. Assuming it takes four hours to start, it loses 4 hours x 200 MW swap x $14,900 (the difference between the $15,000 price spike and the $10 earlier price) = $11.92 million.

Now consider the case where the generator owner actively seeks to manage financial risks. The generator owner knows that there is a low probability of, say, 1% on any given day that 1,000 MW of solar could be lost. Given this knowledge, the generator weighs up the expected cost of being offline during the price spike against the cost of running at minimum generation.

- The cost of being offline is 1% x $11.92m = $119,200.

- The cost of running at minimum generation (min gen) of 100 MW for the whole day is 12 hours x 100 MW x (50-10) = $48,000.

Given the cost of running at min gen is lower than the expected value of being offline, the generator chooses to run at min gen. Running at min gen positions the generator to take advantage of the price spike. On observing the spike it can ramp up to 200 MW within an hour, and so only loses in expected value terms 1% x 50 MW x $14,900 = $7,450 for a total cost of $48,000 + $7,450 = $55,450.

Overall, the generator is better off generating at min gen for a small loss so that its able to defend its contract in the 1% chance that a shock causes the price to spike to $15,000/MWh.

Source: AEMC analysis

As outlined in Box 5, there are financial consequences for market participants of not maintaining reserves. These financial incentives can be significant, meaning that individual market participants understand how to appropriately manage risk. There is no evidence to suggest that this incentive will go away when the nature of the risk changes from being a risk driven by the probability of changes in operational demand, to a risk driven by the probability of changes in VRE generation output.

The Commission is interested in stakeholder views on this.

The above analysis raises the following question: is there something inherently riskier, or less certain, about the probability of changes in VRE generation output, that would cause a breakdown in the physical commitment of reserves to manage the risk?

If someone considers that the risks are increasing (not because the *magnitude* of risk is increasing, as the market price cap is the same, but because the *probability* of the risk is increasing with more VRE forecast errors occurring), then the most logical response would be to increase the value placed on having flexible headroom (reserves) physically available to manage the increased risk.

We therefore consider that there is likely only a low risk that the future power system will develop in a way where the generation mix is largely inflexible. This means that there would likely be a low risk that the future power system would not have the physical capability to be sufficiently flexible (if committed and positioned appropriately) to address any increases in variability and uncertainty of net demand on the power system that may occur over the transition.

4.1.3 The current arrangements are addressing reserve shortfalls in operational timeframes

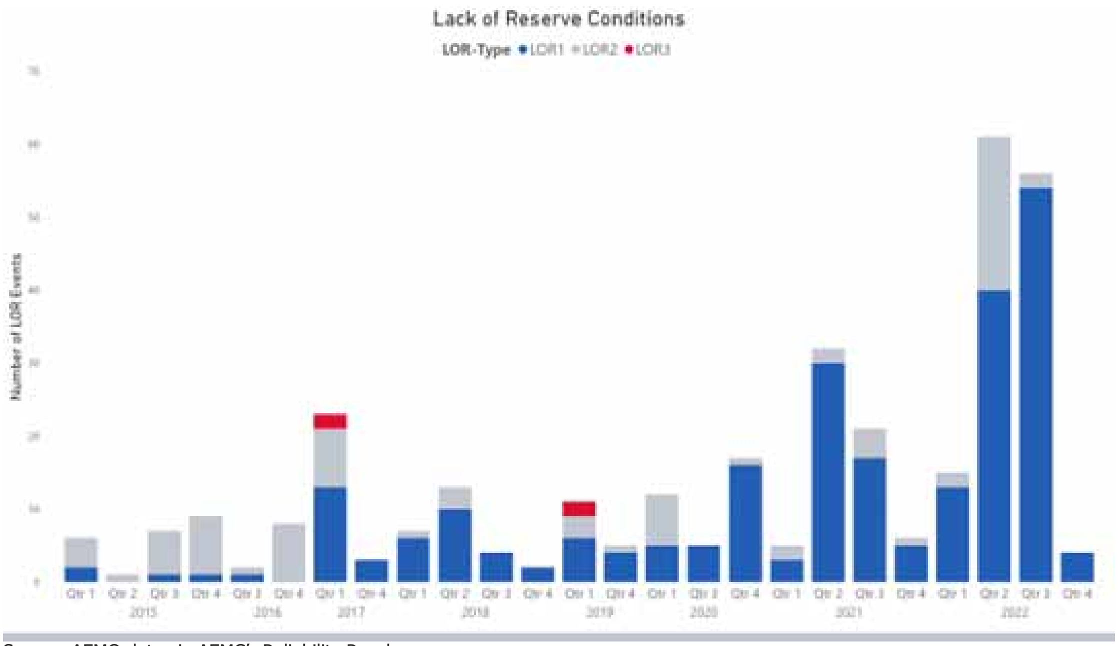
A reliability event for the purposes of this paper is one where there was insufficient generation, demand response, or interconnector capacity to meet consumer demand. These conditions in the system are also referred to as a LOR 3 condition, meaning that the *actual* available electricity supply is equal to or less than the operational demand.[53] LOR3 conditions are identified in red in the chart below.

LOR conditions not associated with a reliability event are represented in blue (LOR 1) and grey (LOR 2). In these situations, there is a *forecast* lack of reserve. However, in response to this forecast, market participants respond or AEMO uses intervention actions, which avoids *actual* shortfalls occurring.

An LOR 1 condition signals a reduction in predetermined electricity reserve levels, encouraging generators to offer more supply, or large industrial and commercial consumers to reduce their demand. At this stage, there is no impact to power system security or reliability and AEMO continues to monitor reserve levels to maintain adequate supply.

An LOR 2 condition exists when reserve levels are lower than the single largest supply resource in a state. At this level, there is again no impact to the power system, but supply could be disrupted if a large incident occurred.[54]

Figure 4.1: Actual LOR Conditions



Source: AEMO data via AEMC's Reliability Panel

The figure demonstrates that despite the rise in LOR 1 and LOR 2 notices (blue and grey bars) i.e. increases in occurrences of a forecast of lack of reserves, there is no correlation to an actual reliability event occurring (red bar), where actual supply to customers was interrupted.

53 For more information on LOR's see chapter 2.

54 LOR condition definitions drawn from AEMO, LOR Notices Fact Sheet, available from https://aemo.com.au/-/media/files/learn/fact-sheets/lor-fact-sheet.pdf?la=en

Looking further back in the past, there have been only four events in the past decade in which a reliability event or LOR3 condition has been declared: in South Australia in 2016-17 and in Victoria in 2018-19.[55] This indicates that the current market signals have so far been sufficient to incentivise participants to address a possible reliability issue prior to AEMO intervening in the market to maintain reliability. Despite the increase in forecast LOR notices in recent years, there is not a clear discernible trend that actual LOR3s (i.e. a reliability event where customer supply was interrupted) are increasing. This suggests that the reliability frameworks are managing these challenges.

As discussed in chapter 2, AEMO procures RERT from out-of-market generation and demand response resources to manage circumstances where the market has not delivered reliability outcomes consistent with the reliability standard or IRM. In 2021-22, the amount of RERT activated was a record for the NEM.

This was dominated by the June market suspension/administered pricing period. RERT was only activated once outside of these events.[56] Further details of recent RERT activations are provided in appendix A.

In addition to RERT, AEMO can issue reliability directions to maintain the power system in a reliable operating state. Historically, AEMO has rarely used directions to manage reliability-related events. Over the last five years, 99% of directions have been issued for security-related events. AEMO's recent reliability directions are described further in appendix A.

Reliability directions are not frequently used, as reliability events generally occur when market prices are high, providing a strong financial incentive for generators to make themselves available for dispatch. AEMO would only direct for reliability when there is technically available generation that is not bidding in.

RERT activation and directions for reliability in recent years were dominated by circumstances around the June APP/market suspension event. During this event technically available generation withdrew from the market in response to high input fuel costs, limited energy availability, and the administered price cap (APC) which at that time was $300/MWh. This resulted in AEMO directing generators on to manage reliability. Net of this particular event, there are no observable trends on the use of either reliability directions or RERT activation, which supports the view that the current arrangements have performed well to date in terms of meeting reserves needs.

The Commission also notes that since this time, a number of actions have progressed to ensure we address issues arising from this event, including the Panel RSS review recommendations,[57] the APC rule change that raised the APC from $300/MWh to $600/MWh,[58] and the review of the form of the reliability standard and APC.[59]

55 AEMO, Market Notices, https://aemo.com.au/en/market-notices?marketNoticeQuery=&marketNoticeFacets=

56 This occurred in Queensland in February 2022 and was caused by increased demand driven by hot and humid weather conditions, and generator outages resulting in insufficient reserves.

57 For more information see https://www.aemc.gov.au/market-reviews-advice/2022-reliability-standard-and-settings-review.

58 For more information see https://www.aemc.gov.au/rule-changes/amending-administered-price-cap.

59 For more information see https://www.aemc.gov.au/market-reviews-advice/review-form-reliability-standard-and-apc.

4.1.4 The current arrangements are incentivising developments in a future fleet that can meet reserve needs in investment timeframes

There are existing investment signals encouraging investment into the market, such as the market price settings for the wholesale market, the accompanying contract market, and then various other incentives such as jurisdictional schemes that seek to provide prices and information to prospective investors to invest in the market. These arrangements, as well as current reforms to these arrangements, are discussed in chapter 3.

The data on investment indicates that there is a significant pipeline of investment in new flexible and enduring capacity in the NEM, suggesting the current arrangements are likely to also address reserve shortfalls in investment timeframes.

AEMO's generation information webpage[60] shows there is significant flexible capacity proposed to enter the power system. This provides a degree of confidence that the current market signals and supporting schemes are attracting the right forms of generation and storage capacity which are needed to balance changes in net demand and maintain system security and reliability in operational timeframes.

Clean Energy Council data shows that recent investment may not be aligned with the investment needed to meet the ISP step-change scenario. The Commission will continue to monitor the situation but, at this stage, there is not enough evidence to suggest that this is part of a broader downward trend. Further, the scale of potential investment coming down the pipeline is still strong. For example, eight projects commenced construction in the first quarter of the year.[61] In addition, recent analysis by Wood Mackenzie indicates that Australia is leading the global market for battery energy storage systems, with the total pipeline now exceeding 40 GW.[62] The analysis suggests that this is the result of the "competitive wholesale and frequency control markets offering diverse revenue streams for battery storage, and significant funding from the Australian government providing revenue certainty to storage projects."[63]

This indicates that the current arrangements described in chapter 2 provide strong incentives for the entry of flexible and enduring capacity, see Figure 4.2.

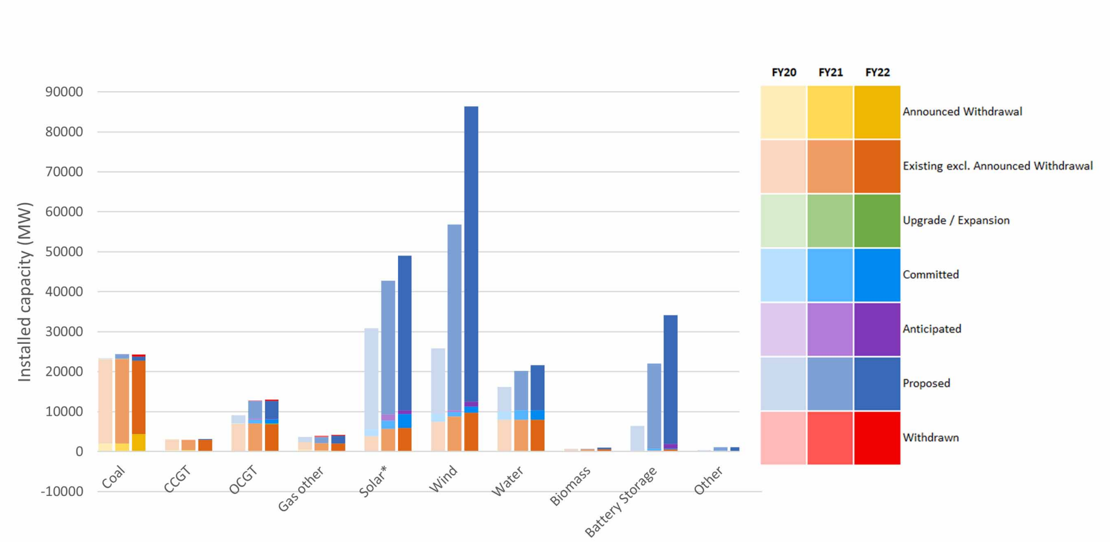
60 For more information see aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

61 For more information see https://www.cleanenergycouncil.org.au/news/clean-energy-construction-peaks-as-investment-pipeline-battles-headwinds.

62 For more information see https://www.woodmac.com/press-releases/australia-leads-global-market-for-battery-energy-storage-systems/#msdynttrid=147EjHKSv5u9PsXCeS-L6nV8IkKyNaQibNO9GJk5BIU.

63 Kashish Shah, senior research analyst at Wood Mackenzie, https://www.woodmac.com/press-releases/australia-leads-global-market-for-battery-energy-storage-systems/#msdynttrid=147EjHKSv5u9PsXCeS-L6nV8IkKyNaQibNO9GJk5BIU

Figure 4.2: Pipeline of generation investment



Source: AEMO generator information survey data via the AMPR 2022

While we appreciate that not all proposed capacity will translate into committed and commissioned capacity on the power system, the trend toward investments in new flexible and dispatchable capacity across all regions of the NEM is still prominent.

Before a project is considered "committed" by AEMO, material costs are sunk in scoping, designing, procuring land and development consents, negotiating connections and securing equity and debt funding. The fact that developers and investors are willing to sink these costs for potential investments in very flexible capacity, based on the incentives present under current market frameworks, is a significant sign that the NEM is more likely to evolve toward a system with much higher levels of capacity that is very flexible over shorter durations.

We have also heard from stakeholders that participants with existing inflexible scheduled plant are making investments to increase the flexibility of their plant. For example, AGL has invested in upgrading Barker Inlet so that it can start up and ramp within minutes. AGL indicates that the station is "capable of operating at full capacity within five minutes, providing a rapid response to changes in renewable generation supply".[64] Other generators are also considering investments to reduce the minimum generating limits on coal units, increasing the flexibility of their operating ranges.

4.1.5 Modelling suggests that the future fleet will be sufficiently agile to meet reserves needs

The rapid pace of the energy transition makes it difficult to accurately predict the capability of the future generation mix to maintain sufficient reserves. Market dispatch modelling was undertaken to help shed some light on these issues. The modelling tested how the power system may perform throughout the transition and whether there are potential future fleet

64 For more information see https://www.agl.com.au/about-agl/how-we-source-energy/barker-inlet-power-station.

mixes that are more or less robust to an increasing need for in-market reserves. While this modelling was undertaken in 2021, the Commission considers its conclusions are still relevant.

The modelling sought to understand how various potential future generating fleets may respond throughout a single day when exposed to significant shocks and unforeseen events. Generating fleets from four NEM regions were tested, both in their current state and a wide range of potential future development pathways. The modelling results provide useful insights into:

- the relationship between variability and uncertainty
- the physical capability of various fleets to meet demand throughout the day.

The modelling did not evaluate the price effect of introducing a new market to explicitly procure reserves. Rather, it sought to test how the current and potential future power system could perform, to provide insights into whether an explicit operating reserve market would be valuable in meeting reliability and security needs, both now and in the future.

BOX 6: KEY INSIGHTS FROM THE MODELLING

Key insights from the modelling indicate that the current fleet is not well suited to operation in a future with high volumes of VRE generation. However, a fleet that evolves to firm renewables with high flexible storage technologies will likely have sufficient flexibility duration to manage uncertainty and variability into the future.

The insights are arranged by the timeframes over which reserves are needed:

1. Flexibility in operational timeframes: five minutes to one hour
2. Availability over a day: 24 hours

1. Flexibility in operational timeframes: five minutes to one hour

A key takeaway from the modelling exercise is that the ability of the generating fleet to respond quickly to uncertain events is:

- **enhanced** if the region develops by firming renewables with highly **flexible** capacity, such as batteries and pumped hydro, that takes seconds/minutes to start up.
- **reduced** if the region develops by firming renewables with relatively **inflexible** capacity, such as slower responding gas, that takes close to 30 minutes to start-up before it can ramp.

For all regions, the more flexible fleets (high battery fleets) produced less severe energy gaps in operational timeframes than the comparable inflexible fleet (high gas fleets). Across all regions:

- The 40% renewable fleet with **high battery**, low gas performed **better** in operational timeframes than the comparable 40% renewable fleet with high gas, low battery.

- The 80% renewable fleet with **high battery,** low gas performed **better** in operational timeframes than the comparable 80% renewable fleet with high gas, low battery.

2. Availability over a day: 24 hours

Another key finding from the modelling is that if the system develops by firming renewables with capacity that is limited in duration (MWh), such as storage technologies, then energy gaps may arise if that capacity is not adequately pre-positioned to meet the needs of the system throughout the whole day. This issue does not tend to arise if the system develops with a heavy reliance on gas, because that technology is not limited in duration by its fuel source. The extent of this issue is heavily dependent on the behaviour of storage capacity.

As discussed elsewhere in this chapter, we expect that the participant self-commitment of reserves in these cases will be informed by the risks faced by participants in the market and how they manage those risks through commitment decisions. It is our view that market participants' resources and analysis, combined with their incentive to manage risks, should result in the collective commitment of reserves sufficient to meet the physical needs of the system.

As discussed in earlier sections of this paper, it appears that current market signals are driving significant investment activity in very flexible equipment (such as batteries) and little to no investment activity in slower responding equipment. This may lead to the view that the fleet is likely to transition closer to the flexible pathway modelled.

The modelling further suggests that not all storage is equal. It highlights that a future fleet with a high proportion of energy storage will need to maintain sufficient state of charge to manage potential longer duration events. This suggests that long duration storage could be particularly important to maintaining reliability in a future where there is limited generation capacity that is not constrained in duration by its fuel source.

There is a growing pipeline of battery energy storage systems in the NEM, as well as a number of pumped hydro projects in Queensland[65] and Tasmania.[66] This suggests that the generation fleet is evolving to meet the reserve needs in both the medium and the longer term.

These results should be read in light of the assumptions of the modelling, principally that the model assumes the system is largely intact and does not include interconnection, demand response or the impact of participant self-commitment decisions (whether rational decisions to manage risks or other less explicable decisions). These assumptions are viewed as imposing a degree of conservatism on the model's outputs. If these assumptions were relaxed, it is likely that the ability of the future fleet to manage increasing reserves needs would be still greater, which would further reinforce the conclusions drawn.

Further details of the modelling are provided in appendix C.

65 For more information see https://www.epw.qld.gov.au/about/initiatives/pumped-hydro-in-queensland.

66 For more information see https://www.hydro.com.au/clean-energy/battery-of-the-nation/pumped-hydro.

4.2 An operating reserve market would centralise reserves procurement

4.2.1 Operating reserve market options were discussed in the previous directions paper

An operating reserve market is a mechanism for the explicit procurement of reserves by a market operator. It separates the procurement of reserves from the self-commitment of in-market reserves that occurs from the procurement of energy. An operating reserve market can procure availability in operational timeframes (minutes to hours).

Various operating reserve market specifications were discussed in the AEMC's previous directions paper, published in January 2021, related to these rule change requests.[67] These included:

- A co-optimised operating reserve market — a market that would be co-optimised with the energy and FCAS markets, for resources with the capability to produce energy from the next dispatch interval.
- A co-optimised availability market — a market to procure availability in the dispatch interval 30-minutes ahead, co-optimised with the energy and FCAS markets.
- A callable operating reserve market — a market that sets capacity aside from the energy and FCAS markets and calls upon it if it is required to become energy in a later dispatch interval. This option is in essence what is proposed in the Iberdrola rule change request.
- A ramping commitment market — a 30-minute raise and lower "ramping" service using the existing framework for FCAS market design. This option is largely what is proposed in the Delta Electricity rule change request.

Stakeholder feedback to the design options explored in the directions paper was mixed. There was no clear consensus on the preferred operating reserve model should such a market be introduced:

- GE Renewable Energy, Tesla, Snowy Hydro and UNSW CEEM were supportive of a co-optimised operating reserve; while Iberdrola were specifically not supportive
- AEMO was supportive of a co-optimised availability market
- Stanwell, Flow Power and Iberdrola supported the callable operating reserve; while Snowy Hydro specifically opposed this
- St Baker Innovation Fund and ERM Power were supportive of the ramping commitment market, while a significant number of stakeholders opposed this.[68]

Other stakeholders suggested various optimal design characteristics, but did not specify one option over another due to a lack of information on the need and/or designs.

67 For more information see https://www.aemc.gov.au/sites/default/files/2021-01/Reserve%20services%20directions%20paper%20-%205.01.2021%20-%20FINAL.pdf.

68 The stakeholders who were not supportive of this option include the Australian Aluminium Council, CEC, PIAC, CS Energy, Flow Power, Snowy Hydro, Iberdrola, Enel X, and Tesla.

4.2.2 AEMO's technical advice refined this option

The Commission thought it would be helpful to consider a particular operating reserve market design to inform our considerations of the costs and benefits of implementing an operating reserve market. This is because there are many variants of such mechanisms, and it was therefore useful to consider a specific model to illuminate:

- how it would work, should it be implemented in the NEM
- whether it could be more efficient and effective than the current NEM design.

The Commission asked AEMO to provide technical advice on design elements of an operating reserve market. In order to facilitate this technical advice, the AEMC provided a sketch of a 'working model' for an operating reserve market, which was designed in consultation with the market bodies and industry stakeholders. We noted that this was indicative, and was provided as a starting point for AEMO's advice.

This working model suggested core features of a 30 minute co-optimised operating reserve market. The market operator would procure, on a rolling basis in every five minute dispatch interval, a certain volume of operating reserves in NSW with the capability to be dispatched as energy in the dispatch interval 30 minutes ahead.

AEMO refined this working design model in its technical advice to suggest a 1-4 hour operating reserve mechanism, which would allow manual intervention to ensure adequate reserves if required. AEMO considered that the earlier scheduling of resources would provide greater confidence to the system operator of future delivery of energy in timeframes relevant to intervention decisions, and additional ability to increase availability to bring units online.

This working model design was chosen based on the Commission's analysis, and was somewhat supported by stakeholder feedback to the 2021 directions paper. Such a model was preferred because the co-optimisation with the energy market would mean the most efficient market outcomes were achieved, if such a mechanism was implemented.

AEMO's advice has been integral to our assessment of the potential merits of implementing an operating reserve market. It has provided sufficient information to enable the Commission to compare the potential performance of an operating reserve market against the current market arrangements in terms of meeting reserve needs.

This technical advice and the design set out in it form the basis of our discussion below.[69]

BOX 7: OPERATING RESERVE MARKET DESIGN

The design features of the operating reserve market design outlined in AEMO's technical advice are described below, with further information provided in appendix A.

Procurement of reserves would be centralised, with AEMO arranging for the commitment of availability from participants in advance of real-time, with procurement of reserves likely

69 For more information see https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf.

being co-optimised with the energy and FCAS markets. Reserves could be procured every five minutes to be dispatched as energy at some point in the future (ahead of real-time). This could be from five minutes in the future up to several hours.

The quantity and price of reserves to be procured could be set according to an operating reserve demand curve, reflecting the value consumers place on having capacity in reserve and incorporating the value and probability of lost load.

A market participant could, for a given dispatch interval, offer its capacity (simultaneously) in up to ten price bands in each market to provide energy, FCAS, and 'reserve'.

AEMO would co-optimise energy, FCAS and reserve markets and enable capacity in reserve in MW. The obligation on energy enabled as 'reserve' would to be capable of being dispatched as energy in a future dispatch interval, with the future period determined by the specific market design adopted. This could range from five minutes up to several hours.

The model could operate on a causer-pays basis. Under this model, the causers of demand and generation uncertainty would be required to cover the cost of needed reserves.

Source: AEMC analysis of AEMO's technical advice.

4.3 An operating reserve service would not promote the long-term interests of consumers

The purpose of this chapter is to consider two questions in relation to the issues identified by the rule change requests and other stakeholders. Earlier sections of this chapter considered the first question, which is whether the current arrangements are expected to manifest sufficient in-market reserves on the system as the transition proceeds.

This section addresses the second question: whether an explicit operating reserve market would offer performance benefits relative to the current arrangements.

4.3.1 The Commission does not consider there are benefits of an operating reserve market

An operating reserve design should not be viewed as a simple 'add on' to the existing NEM design, but rather a fundamental change to the way that reliability needs are met in operational timeframes, potentially resulting in significant costs. It is important therefore to carefully consider the proposed benefits of such a market and whether these could be greater than those offered by the current arrangements.

An operating reserve service could provide greater visibility of market participants' reserve decisions to the market operator. This could help AEMO to mitigate risks should market participants not manage their risks well. However, the Commission has not seen evidence that participants will struggle to manage their risks as the transition proceeds.

The current arrangements are based around providing information to the market on potential future reserves needs while also providing financial incentives (both through the spot market and related contract market) for market participants to best manage reserves in order to mitigate risk. We consider that these risks imposed on the market (which may evolve as the power system transitions) should continue to incentivise participants to make sure there are sufficient reserves to manage unexpected ramps. This involves participants committing reserves to manage their financial risks, which in turn should meet the physical needs of the system.

We therefore have no reason to suggest that a future characterised more by VRE forecast uncertainty would cause a breakdown in the relationship between financial risks and the commitment of reserves. The value of an operating reserve market to help meet the system's need for reserves, over and above the current arrangements, therefore appears to be low.

Looking at investment timeframes, the Commission considers that the current market arrangements are working effectively to incentivise the right mix of plant to mitigate the risk of low reserve conditions.[70]

In addition, the Commission considers that an explicit operating reserve market is not a tool to provide investment signals. Indeed, there is a risk that such a market could dilute investment signals, particularly for the types of fast-start, responsive plant that would best respond to an increased need for reserves. If this is the case, then the implementation of an operating reserve service would be considered to be at odds with the direction of recent reforms, particularly five-minute settlement, which involved moving to stronger signals to incentivise investment in fast-start plant. It could also favour certain technologies over others.

While a new operating reserve market may provide more visibility of reserve levels it is unlikely that this would be translated into system-wide benefits, given an operating reserve service would likely result in greater costs being borne by market participants and passed on to consumers.

These would likely include direct costs, including implementation costs for AEMO and for market participants who may need to upgrade their systems to accommodate trading in a new market. There may also be indirect costs associated with an operating reserve market. For example, such a product like an operating reserve would be difficult to hedge, imposing increased risks and likely costs on market participants, which would flow through to consumers.

In light of these findings, the Commission considers that an operating reserve service would likely not promote the long-term interests of consumers. This is supported by analysis of an operating reserve market against our assessment criteria, as outlined further in section 4.4 below. Therefore, we do not consider introducing an explicit operating reserve market is necessary.

Noting that it has been more than two years since the publication of the previous directions paper, the Commission considers that these conclusions are supported by stakeholder submissions to the 2021 directions paper, which in summary were that:

70 For more information see appendix C.

- many stakeholders considered that the current market and government interventions were already driving investment in dispatchable capacity
- many stakeholders also considered that variability and uncertainty are issues, with some suggesting a new service was needed and others suggesting more work be completed before this conclusion can be made
- some stakeholders were not sure a new service was needed, given the context of other potential changes under consideration at the time, including other resource adequacy mechanisms such as the capacity investment scheme
- only one submission suggested that a new reserve service was urgently needed.

We welcome stakeholder views on this conclusion.

> QUESTION 1: COMMISSION'S DECISION
>
> Do you agree with the Commission's decision not to recommend the implementation of an operating reserve market?

4.4 Analysis of an operating reserve market against our assessment criteria

Our conclusion is supported by an assessment of an operating reserve market against the assessment criteria outlined in Section 1.3.4. Further detail of this assessment is set out below.

4.4.1 Promoting power system security and reliability

The Commission does not consider that an operating reserve service would have any additional value in meeting the power system's need for reserves for a reliable power supply, as discussed above.

We have outlined our view that the financial risks imposed on market participants under the current arrangements should manifest sufficient reserves on the system into the future. There is no evidence to suggest that market participants will cease to manage their risks as the transition proceeds.

In relation to investment timeframes, our analysis has highlighted that investment signals are being addressed through work on market settings and government schemes. Given this, we do not consider that the operating reserve would be a tool that would primarily provide investment signals. Indeed, we consider that there is even potentially a risk that an operating reserve market could dilute the investment signals that are helping to drive the development of flexible plant in the NEM. An operating reserve, which would have parties be on stand by for at least 30 minutes, would likely dilute or obfuscate the granular five minute price that parties face at the moment. It is this five minute price that creates incentives and signals for fast-start plant to be online. At an extreme, the introduction of an operating reserve would work against these incentives.

4.4.2 Appropriate risk allocation

As noted above, the current arrangements place real-time risks on participants, who are best placed to manage these, given that they face financial incentives to do so. We continue to believe that this is the appropriate place for these risks to be managed, rather than some of these risks being centralised. Participants have the best knowledge of their own equipment to best make sure that reserves are provided.

We also consider that there are examples showing that participants are managing such risks even with the increasing VRE-driven uncertainty that is occurring. Take for example the South Australian region; that region has evolved over investment timeframes to be more flexible. Participants appear to be committing their flexible capacity at times of higher forecast uncertainty.

The shift toward a more flexible system is also occurring in other regions, and we are seeing significant volumes of flexible capacity proposed for entry across the NEM as discussed in chapter 3. There are also plans for investment in transmission to increase transfer capacity proposed between regions.

4.4.3 Technology neutral

An operating reserve would be technology neutral. Any unit could participate in the market, provided it could meet the capability of the product specified. The specification of the product is key here — it is more likely to favour particular types of plant. AEMO's technical advice notes that a one to four hour procurement window is necessary to provide adequate reserves:

> "Following detailed consideration of interaction with dispatch processes, and only if strict compliance measures were in place, AEMO's preference would be for a 1-4 hour Operating Reserve mechanism that allows manual intervention to ensure adequate reserves if required."[71]

While this is, in theory, technology neutral, the longer procurement window of an operating reserve market lends itself to incentivise longer duration plant and/or plant with greater ramp times (e.g. coal fire generators, slow-responding gas generators). This is in contrast to the existing market design that is also technology neutral but provides five-minute price signals that can reward faster responding plant that takes advantage of higher price spikes.

Implementation of an operating reserve market could therefore weaken the investment case for more flexible technologies, such as batteries. Again, this could place an operating reserve market at odds with the direction of recent market reforms and with government schemes designed to incentivise investment in more flexible technologies.

The Commission considers that the current market arrangements are both technology neutral and provide long-term price signals to incentivise the right types of plant to manage a transitory increase in reserve needs.

71 AEMO's technical advice https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf.

4.4.4 Flexibility

An operating reserve service constitutes a more centralised approach, which relies on the operator planning and procuring enough reserves to ensure reliability across investment and operational timeframes.

Because these reserves would be locked in ahead of time, some of the flexibility present in the current market where participants adjust their availability in response to new information would be removed. Such flexibility is important and means the market is adaptable to changing market and external conditions. It also helps prices reflect the actual costs of the system, given there is flexibility to adapt to the situation present at a particular time.

In contrast with this, the current market structure relies on participant self-commitment of resources rather than central procurement. The risk of over-delivery of capacity is faced by the market participants (rather than consumers). Over-investment of capacity or over-commitment typically results in lower prices in the energy market for a short time period as there is oversupply and as the market adjusts to this period of oversupply.

The risk of under-delivery of reserves and energy is faced by consumers in the reliability of the system. The reliability settings (such as the MPC) are designed to ensure that the market participants face sufficient risks, in investment and operational timeframes, to ensure they provide reserves and energy to a level of reliability that consumers value.

4.4.5 Transparent, predictable and simple

Implementing an operating reserve market would introduce complexity into the market. Complexity is in and of itself not necessarily a bad thing given the electricity market is a complex construct. However, it does cause some costs, particularly at the start as the market is more 'new' to participants. In contrast, our proposed incremental reforms focus on improving transparency, which necessarily help to make clearer the current complexity in the market.

4.4.6 Costs

The operating reserve market would be a substantial change, which would come with costs for both AEMO and participants. AEMO's technical advice sets out estimated costs.

AEMO costs for the implementation of an operating reserve market were estimated as part of the NEM 2021 business case. Implementation costs were estimated to be 'large' through initial 't-shirt sizing' estimates, with impacts across NEMDE, pre-dispatch, IT, settlements and other areas. Upfront costs for AEMO are estimated as approximately $11.4m +/-40% and ongoing costs are estimated to be $7.8m (over a 10-year period).[72]

Service providers who choose to participate in the market may incur costs of updating systems and processes in order to participate in the operating reserve market, as well as

72 This is based on the assumption that the scheduling of operating reserves would be performed by NEMDE, forecasting and ST PASA redevelopment projects are able to provide necessary inputs to the determination of the ORDC and that the replacement of causer pays system can be leveraged for the settlement of the system.

participating in relevant consultations. The Commission expects these to add to the costs of the above.

As outlined in earlier parts of this chapter, there may also be indirect costs associated with an operating reserve market. For example, such a product like an operating reserve would be difficult to hedge, imposing increased risks and likely costs on market participants, which would flow through to consumers.

5 INCREMENTAL IMPROVEMENTS TO THE EXISTING ARRANGEMENTS

BOX 8: KEY POINTS IN THIS CHAPTER

- While we consider that the implementation of an explicit operating reserve market would not promote the long-term interests of consumers, the Commission recognises that incremental improvements to enhance the current arrangements could potentially provide value, particularly as the system transitions to a new operating environment.
- AEMO is already progressing a number of initiatives aimed at supporting the market in meeting increasing variability and uncertainty. These initiatives have a particular focus on improving net demand forecasts and redeveloping ST PASA, and AEMO's focus on these areas is, in the Commission's view, providing value to the market.
- Beyond AEMO's existing initiatives, we are interested in stakeholder feedback on whether there is merit in pursuing further incremental improvements to the existing market design.
- The incremental improvements we have identified for stakeholder consideration are:
  - **1: Develop and publish more information to the market**, with a particular focus on energy limited plant. This would involve AEMO receiving information on storage/state of charge and publishing it in either pre-dispatch or dispatch, with the aim to address the need for more information on the flexibility and duration of plant.
  - **2: Procurement of FCAS at a regional level,** or alternately limiting the amount of FCAS procured from a single region to increase the amount of FCAS procured in other regions. This could allow for frequency stabilisation within a region following a rapid and unexpected change in VRE output, without being limited by interconnector headroom between regions. It could also allow for transmission infrastructure to be used more effectively and may improve network utilisation, potentially avoiding some transmission spend as we move through the transition.
- We are interested in stakeholder views on these proposed incremental improvements. In particular whether:
  - the proposed incremental improvements have merit that is worth exploring, including formalising in the Rules framework
  - there are any other incremental improvements that should be pursued in the absence of an operating reserve market being implemented.
- The process for making a submission is outlined in chapter 1.

5.1 Initiatives already underway to support participants' reserve decisions

AEMO is already progressing a number of beneficial initiatives to support the market in meeting increasing variability and uncertainty as the NEM transitions. These initiatives are focused on improving net demand forecasts and redeveloping ST PASA.

The Commission understands that ongoing work by AEMO to improve net demand forecasts has so far shown successful results.[73] The Commission supports AEMO's continued efforts to improve net demand forecasts. This is discussed further in section 5.1.1.

AEMO's ST PASA replacement project is a comprehensive review of the pre-dispatch and ST PASA methodology.[74] Commencing in 2019, AEMO has consulted widely with industry on the current value of pre-dispatch and ST PASA information to understand how to optimise these systems. While this project is still ongoing, the Commission recognises that it is providing valuable insights into how the industry identifies and manages short-term risks to the power system security and reliability. This is discussed further in section 5.1.2.

5.1.1 Improve accuracy of net demand forecasts

Several projects are underway to improve the accuracy of forecasts. These aim to address the risk of insufficient reserves to manage increasing uncertainty in net demand forecasts.

As discussed in chapter 2, the accuracy of forecasts is critical to ensure informed decision-making by AEMO, market participants, and the energy industry more broadly. Short-term forecasts have implications for how participants bid into the market, while medium- to longer-term forecasts inform investment decisions by participants and provide inputs to the RRO, RERT, and ISP.

Critical to these forecasts are AEMO's forecasts of available capacity for wind and solar generating units (unconstrained intermittent generation forecast (UIGF)) for the purposes of the dispatch, pre-dispatch and PASA processes (that is, forecasts for the period five minutes to two years ahead).[75]

AEMO currently uses the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS) as part of this process. AEMO is also progressing a number of activities to improve the accuracy of both short-term and long-term forecasts.

The Commission discussed changes to improve the accuracy of net demand forecasts in its 2021 *Operating reserves directions paper*. At the time, the self-forecasting trial was in its second year and AEMO had outlined a range of forecast improvements in its 2020 *Forecast improvement plan.* Stakeholders were largely supportive of these initiatives and considered that improvements to forecasting should be pursued.

73 For more information see https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting.

74 For more information see https://aemo.com.au/en/initiatives/trials-and-initiatives/st-pasa-replacement-project.

75 Clause 3.7B of the NER.

For example, Stanwell considered that "incremental changes to improve the accuracy of forecasts (particularly demand, solar and wind forecasts) and refined metrics needed for frequency and ramping, be regarded as business-as-usual".[76] MEU noted that "issues identified through better forecasting and the provision of improved data which, when coupled to the existing incentives, should be sufficient to maintain the existing levels of reliability at no increase in cost".[77] ERM Power "support the continued improvement of forecasts for demand and solar PV" and that they "would go a long way to addressing the perceived risks around uncertainty of net demand".[78]

Short-term forecasts

Forecast trial and results

In 2018, a Market Participant Self-Forecasting trial was initiated as a collaboration between AEMO, the Australian Renewable Energy Agency (ARENA) and industry (forecasting service providers, existing and new wind/solar generators) to explore the benefits of self-forecasting unconstrained wind and solar generation. The initial focus of the trial was to determine the relative benefits of using the participant's five minute ahead dispatch self-forecast in dispatch, in preference to the equivalent forecast from AWEFS or ASEFS.

The AEMC understands that self-forecasting on the five minute ahead (dispatch timeframe) has now been implemented. The AEMC also recognises that AEMO is exploring a number of other system-wide benefits through this trial, by reducing generation forecast error and providing greater autonomy to intermittent generators.[79]

Long-term forecasts

Forecast accuracy report

Each year, AEMO must publish the Forecast Accuracy Report to outline the accuracy to date of the demand and supply forecasts as well as any improvements made by AEMO or other relevant parties to the forecasting process that applies to the following statement of opportunities.[80]

The improvement plan is an important tool to guide investigation work and improvements in forecasting. The 2020 Forecast Accuracy Report illustrated the need for improvements to the accuracy of the distributed PV forecast. Forecast differences remained high in the 2021 *Forecast Accuracy Report* because the assessed forecasts were issued before the improvement work identified in 2020 was completed. The 2021 report highlighted that the

76 Stanwell, submission to the Operating reserves direction paper, 2021, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_stanwell_corporation_limited_-_20210211.pdf, p. 2.

77 Major Energy Users, submission to the Operating reserves directions paper, 2021, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_major_energy_users_-_20210211.pdf, p. 4.

78 ERM Power, submission to the Operating reserves directions paper, 2021, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_erm_power_-_20210211.pdf, p. 4.

79 For more information see https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/participant-forecasting.

80 Clause 3.13.3(A)(h) of the NER.

most recent projections of distributed PV improved and recommended that this be monitored. The 2022 report confirms the success of the improvement initiatives in this area, with actual distributed PV uptake closely aligned with forecast uptake across all regions.

AEMO continues to investigate areas to improve forecast accuracy and identified the following areas in the 2022 report:

- winter maximum demand outcomes
- annual minimum demand
- annual consumption
- generator commissioning
- planned and unplanned outages.

The NER requires AEMO to produce the Forecast Accuracy Report annually. The Commission understands that this report has supported improvements to forecasting through the review of demand, supply, and reliability forecasts across the NEM. Accurate long-term forecasting can assist to incentivise the right mix of capacity to enter the power system where it's needed, which can then provide support in the operational timeframe.

5.1.2 ST PASA replacement project

Under current arrangements, AEMO provides a range of information to participants including information on reserve levels over various time horizons. This is published through the PASA process based on availability information provided by market participants, including:

- ST PASA, which is published every two hours and forecasts capacity and reserve levels every 30-minutes for six days following the next trading day
- PD PASA, which forecasts capacity and reserve levels every 30-minutes from the next 30-minutes to the end of the next trading day.

These processes, which were designed when most of the generation in the NEM was supplied from large thermal units connected to the transmission network, are unable to model some emerging technologies characterising the current transition, including battery storage, virtual power plants and CER. The systems are also unable to incorporate improvements in the modelling of intra-regional network issues, sharing of reserves across different regions and the allocation of energy-limited resources.

AEMO's review is providing confidence that the PD and ST PASA processes will continue to assist participants identify and manage short-term security and reliability risks now and into the future.

While this review is broad and ongoing, the Commission understands that greater information on energy limited plant will continue to be considered as part of the redevelopment project. Specifically, this could include a bi-directional model that can account for state of charge, which AEMO indicates will be introduced into the modelling in June 2024.[81]

81 AEMO ST PASA Replacement Project, Stakeholder workshop #2 — overview of the new process, https://aemo.com.au/-/media/files/initiatives/st-pasa-replacement-project/stakeholder-workshop-2-overview-of-new-stpasa.pdf?la=enadd.

The Commission recognises the value in publishing storage plant reserves in ST PASA. This could assist participants with and without storage to understand the value of their reserves.

We also note that AEMO's ST PASA replacement project includes investigating improvements to the use of uncertainty margins and confidence levels, and proposals on determination of LOR levels. These incremental improvements were also considered in the previous directions paper relating to the improvement of information that could help with the provision of reserves in operational timeframes.[82] Specifically the Commission considered:

- **Publishing additional uncertainty measures** to give participants an understanding of future forecast uncertainty to assist with assessing future risks. The FUM is available to participants under current frameworks.
- **AEMO developing additional metrics or limits** around these parameters, such as changing the LOR framework to include energy, not just capacity. This could communicate the changing need for energy adequacy to the market, thereby supporting investment signals in both the level and type of technology required.

AEMO's review of PD and ST PASA also includes use of uncertainty margins and confidence levels and proposals on determination of LOR levels.[83] Because of this, these incremental improvements are not being considered further by the Commission, given AEMO aims to ensure the PD and ST PASA processes are fit-for-purpose now and into the future.

5.2 Proposed incremental improvements for stakeholder input

The Commission is interested in stakeholder views in whether there is merit in pursuing two incremental improvements alongside the existing initiatives described above:

1. **Develop and publish more information to the market**, with a particular focus on energy limited plant. This would involve AEMO receiving information on storage/state of charge and publishing this in pre-dispatch or dispatch. Discussed further in section 5.3.
2. **Procurement of FCAS at a regional level**, or alternatively limiting the amount of FCAS procured from a single region to increase the amount of FCAS procured in other regions. Discussed further in section 5.4.

We are particularly interested in stakeholder views on the following questions:

QUESTION 2: ADDITIONAL INCREMENTAL IMPROVEMENTS

a) Is there merit pursuing the two additional incremental improvements (detailed further below), including formalising these in the Rules framework?

b) Are there any other incremental improvements that should be pursued in the absence of an operating reserve market being implemented?

82 For more information see https://www.aemc.gov.au/sites/default/files/2021-01/Reserve%20services%20directions%20paper%20-%205.01.2021%20-%20FINAL.pdf

83 For more information see https://aemo.com.au/en/initiatives/trials-and-initiatives/st-pasa-replacement-project for AEMO's ST PASA project.

5.2.1 Options outlined in our previous directions paper

A range of incremental improvements to address uncertainty and variability were outlined in the Commission's 2021 *Operating reserves directions paper.* At the time, there was significant stakeholder support for these incremental improvements, particularly regarding developing and publishing more information to the market. Incremental improvement 1 is similar to what was outlined in the previous directions paper, albeit with some changes to reflect new information that has become available since 2021. Incremental improvement 2 was not discussed in the previous directions paper.

In its 2021 *Operating reserves directions paper, t*he Commission invited feedback on whether additional information is needed to support participants in being able to better meet expected and unexpected ramps in net demand*.* There was significant support from stakeholders for increased information provision with the Major Energy Users (MEU) noting "developing and publishing more information for the market provides better information flow to those market participants exposed to risk and allows them to better manage their exposure"[84], the Australian Energy Council (AEC) expressing "AEMO and AEMC should pursue incremental improvements in existing forecasting and dispatch processes"[85] and Hydro Tas agreeing "there is merit in progressing incremental improvements such as… publishing more information to support better decision-making by market participants".[86]

Powerlink provided a late submission to the Commission's 2021 *Operating reserves directions paper* suggesting an additional incremental improvement option for the Commission's consideration. This is discussed below as Incremental improvement 2.

5.3 Incremental improvement 1: Develop and publish more information for the market

What is the problem to be addressed?

All markets for services require a flow of clear and relevant information to promote competition and efficient outcomes. Market information is likewise important to ensure the efficient provision of reserves, FCAS and energy in the NEM. Participants need relevant and timely information to make efficient decisions relating to the supply of these services.

Market participants use information published by AEMO and gathered from other sources to inform their operational decisions. In a future power system with large amounts of storage capacity on the system, participants are likely to make better decisions to position that capacity to meet the power system need for flexibility and duration of energy reserves if they have the right information available to them.

84 MEU, Submission to the Operating reserves direction paper, 2021, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_major_energy_users_-_20210211.pdf, p. 7.

85 AEC, Submission to Operating reserves direction paper, 2021, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_aec_-_20210211.pdf, p. 4.

86 Hydro Tasmania, Submission to Operating reserves direction paper, 2021, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_hydro_tasmania_-_20210211.pdf, p. 4.

Participants do not current have access to real-time information on the state of charge of storage providers in the NEM (aside from those storage providers themselves). As batteries become a more significant part of the power system, the publication of real-time state of charge information will become increasingly valuable to contribute to efficient decisions relating to the provision of reserves, FCAS and energy. For participants, this information could assist in the efficient provision of reserves over shorter and longer durations. For example, information showing that a region has a low level of reserve duration (in MWh) available from flexible energy constrained sources (i.e. batteries) could:

- signal to storage providers that there is a high value in charging (even at relatively high energy prices) in order to meet the energy needs and account for potential uncertainties later in the day
- signal to other capacity (such as gas generators) that there is a high value in turning on to provide flexible headroom to be available for uncertain events and provide energy over longer durations over the course of the day.

This information could therefore change the decisions participants make to commit reserves in operational timeframes. This could improve the reliability of the system because reserves would be more likely to be physically committed when they are needed. The changes may also promote efficient outcomes, particularly productive efficiency outcomes as a cheaper mix of capacity may be able to provide reserves, FCAS and energy. This change would also likely be relatively inexpensive to implement. Our preliminary view is therefore that the benefits should outweigh the costs.

Description of this incremental improvement: receiving storage information and publishing this in pre-dispatch or dispatch

AEMO currently receives real-time information on the state of charge of large-scale batteries on the power system through SCADA. We understand this is provided as part of the performance standards negotiation process under Chapter 5 of the NER. The Commission considers there may be value in clarifying these arrangements in the Rules to enable AEMO to collect and publish information relating to energy-limited plant.

While AEMO receives this state of charge information, it does not publish information on the state of charge of batteries.[87] Some batteries (such as Hornsdale Power Reserve) currently publish state of charge information on their websites, but this may not be the case for all batteries as more connect to the system.

We consider the appropriate vehicle for the publication of state of charge and energy-limited plant information would be either in pre-dispatch (or five-minute pre-dispatch) or dispatch information. This is because that information relates to the predicted or real status of the prices and outcomes of dispatch. There is a range of options for the publication this information:

87 AEMO may also receive energy limit information for pumped hydro through ST and MT PASA. In conjunction with considering collecting and publishing state of charge information for batteries, we are considering the merits of publishing this information for pumped hydro.

- publication of aggregated information by region on the available energy in MWh from energy limited capacity that is available over various timescales
- publication of aggregated information by region and by technology type (e.g. batteries, pumped hydro etc.) on the available energy in MWh from energy limited capacity
- publication of information on the available energy in MWh for individual generators or connection points.

The Commission sees value in amending the Rules to require AEMO to publish state of charge information in either pre-dispatch (or five-minute pre-dispatch) or dispatch information. We are interested in stakeholders' views on this and whether there is benefit in collating and sharing all, or part, of the information above in a staged approach. For example, batteries first, followed by pumped hydro, and lastly thermal plant. This would reduce the administrative burden for AEMO and allow learnings from each stage to be considered before implementing later stages.

How would this incremental improvement address the problem?

Greater and more granular information on storage capacity could assist participants to better understand the value of being available over the course of the day. For example, if a significant proportion of reserves is being provided by batteries, a non-energy limited plant (for example, OCGT) may wish to make itself available in reserve to address gaps that may arise when battery capacity is used up. As such, this information could:

- better ensure the availability of reserves across all timeframes
- allow more efficient decisions about the commitment of reserves at certain times.

This information should also help participants better manage their reserve availability to address shorter-duration flexibility issues. For example, information showing there is a very low level of stored energy available might change the decisions that would otherwise be made, such as causing a battery to charge at a higher energy price or a gas generator to turn on and run at minimum generation output so it can ramp if needed to cover a price spike.

The Commission is interested in stakeholder views on its assessment of this incremental improvement

The Commission considers this incremental improvement could be valuable in providing the proposed information at a relatively low cost, as this information could be built into existing processes (pre-dispatch or five-minute dispatch).

We also consider that this improvement aligns with the Commission's assessment criteria, particularly with regard to reliability and transparency. It would provide greater information to the market, enabling participants to better assess opportunities and risks in operational timeframes. This enhances a participant's ability to self-commit reserves.

This incremental improvement would not impose significant changes on the market, allowing costs to consumers to remain low. Further, it is a relatively simple approach as it can be achieved in existing processes. While this option is technology neutral by not explicitly excluding a certain type of technology, it provides greater value to resources with storage ability, i.e. batteries or pumped hydro.

The Commission also recognises that there are trade-offs to providing this information, which if this improvement is considered further, we will explore in more detail with market bodies and participants in technical working group sessions. For example:

- The cost of the additional computational difficulty for AEMO to provide this information to participants will need to be weighed against the benefits that the additional information may provide.
- Any projections of state of charge information would require assumptions which could introduce a level of uncertainty, notwithstanding this uncertainty exists already absent this information being published to the market.
- More sophisticated participants may already calculate and use extra information, akin to the information noted above, to inform their decision-making. Centrally publishing this information may reduce any information asymmetry, benefiting the overall efficiency of the energy market to allocate reserve capacity. However, there may also be commercial sensitivities that need to be considered.
- There is also the risk of anti-competitive behaviour associated with increased supply-side information transparency. For example, increased monitoring of competitors actions may inform participants of their competitors' operational limits, and this could lead to anti-competitive or inefficient outcomes (particularly in real-time). Potential scenarios include:
  - participants setting prices beyond efficient levels
  - collusion.

If stakeholders see value in progressing this option further, the Commission will investigate how material this issue is and what mitigating actions could be pursued. For example, aggregating the state of charge information until such time that there are enough suppliers in each region to mitigate the risk of anti-competitive behaviour.

Incremental improvement to increase information provision is not being pursued

The January 2021 directions paper invited input on another incremental improvement that would allow generators to include additional ramp rates in their electricity market bids.[88] This option is not being pursued because the Commission considers it an inefficient means of providing more flexibility.

This idea was to allow participant bids to include multiple ramp rates (two or more). NEMDE would solve for the optimal dispatch of the system taking into account both the energy bid and any additional payment to unlock flexibility. This additional payment would only be needed if the system is very limited in the capability to ramp to meet net demand needs. If it appears that the underlying flexibility in real-time is low, participants may wish to make more flexible capacity available to capitalise on potential price spikes.

88 For more information see https://www.aemc.gov.au/sites/default/files/2021-01/Reserve%20services%20directions%20paper%20-%205.01.2021%20-%20FINAL.pdf.

The Commission received mixed feedback on this incremental improvement. While the AEC noted that "permitting dual ramp rate bidding would be one such minimalist enhancement that goes directly to one motivation of this line of work"[89] several other stakeholders were concerned on the cost/benefit trade-off of this improvement. Hydro Tas, The University of New South Wales (UNSW) and GE Hydro all contended that this change would be significantly complex and costly. Hydro Tas noted "multi-period optimisation for the pre-dispatch and real-time markets, while potentially significant, is more complex and will require careful consideration"[90], UNSW also suggested "it [multi-period dispatch] involves significant implementation costs and challenges"[91] and GE Hydro discussed "this [multi-period dispatch] would ultimately lead to lower cost VRE being curtailed in order for higher cost coal to run, increasing cost to consumers." They further contended that it "runs counter to the intent of the transition to five-minute settlement" and that "given that the cost and complexity... it doesn't appear to be worth pursuing further".[92]

This incremental improvement has not been given further consideration because it is an inefficient means to unlock a material amount of flexibility. Furthermore, it is unlikely to be an effective tool for the long-term management of uncertainty and variability on the system. The volume of additional flexibility that may be provided is not significant enough to warrant this change.

This improvement is also mostly focused on unlocking flexibility from incumbent coal generators. As the power system transitions the fleet of coal generation will diminish, and the value of any additional flexibility they may be able to provide to the system will also diminish. It therefore does not support the growing proportion of generation capacity becoming available from flexible batteries and VRE, nor would it be consistent with the emissions reduction considerations which will be introduced into the NEO later this year. This improvement also does not allow for the value of reserves to be more clearly identified by the market. Therefore, this improvement does not support any significant productive or allocative efficiency gains.

5.4 Incremental improvement 2: Procurement of FCAS at a regional level

The previous improvement discussed in this directions paper generally addresses reliability considerations related to timeframes from five minutes to pre-dispatch.

89 AEC, Submission to the Operating reserves directions paper, 2021, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_aec_-_20210211.pdf, p. 4.

90 Hydro Tas, Submission to the Operating reserves directions paper, 2021, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_hydro_tasmania_-_20210211.pdf, p. 4

91 UNSW, Submission to the Operating reserves directions paper, 2021, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_unsw_collaboration_on_energy_and_environmental_markets_ceem_-_20210211.pdf, p. 7

92 GE Hydro, Submission to the Operating reserves directions paper, 2021, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_ge_hydro_-_20210208.pdf, p. 2.

The changes in the energy market that are leading to greater variability and uncertainty in timeframes of five minutes and longer are also influencing shorter timeframes of less than five minutes. In these shorter timeframes, it is the procurement of FCAS that assists in balancing supply and demand.

Incremental improvement 2 therefore considers changes to FCAS that could assist in managing the impacts of an increasing need for reserves as this relates to sub five minute timeframes. This also allows for the more efficient use of existing network infrastructure, improving its utilisation and supporting reduced costs for consumers. For more information on this option, please refer to Powerlink's late submission on this issue.[93]

What is the problem to be addressed by this option?

Security issues could arise in the future from the sudden and unanticipated reduction of VRE output from a renewable energy zone (REZ), another large-scale renewable generation source or from a sufficient number of smaller sources. To the extent the uncertainty manifests within a dispatch interval (DI) it would require an FCAS response from the NEM to maintain frequency within the target band. Regulation FCAS would be the primary tool to maintain the supply-demand balance within the DI.

Global procurement of FCAS may be challenged in the future if the size of the change is sufficiently high that procuring FCAS from outside the region is limited by available headroom on region-to-region interconnectors. Such an instance would require at least some FCAS to be procured within the region so as to avoid the capacity limits imposed by the interconnector or interconnectors.

The above scenario is increasingly likely in the future where:

- REZs are developed in increasing numbers and of increasing size within NEM regions, raising the size (in MW) of swings in output related to changing weather patterns
- aggregate levels of VRE generation in the NEM increase in response to increasing electricity demand (which we note is anticipated under the ISP).

Improving the supply-demand balance within DIs can also assist over multiple DIs. The use of regulation FCAS helps to move generation levels in the direction they need to go so that they are in a better position to respond to the next dispatch target.

In addition, Powerlink sets out that the design limitations for double circuit REZs resulting from interactions with existing FCAS and operating reserve arrangements impinge on the allowable transfers under system normal ratings, and following a contingency event. This limits the potential size of REZ developments and may result in connection assets that are not scale efficient. The smaller the potential size of REZs, the more REZs required. At an extreme, this results in less efficient use of the transmission network and higher connection costs which will ultimately flow on to consumers.

This improvement would also allow for transmission infrastructure to be used more effectively and improve its utilisation. For example, procurement of regional FCAS could provide greater

93 For more information see https://www.aemc.gov.au/sites/default/files/2023-06/Powerlink%20submission%20June%202023.pdf.

flexibility in how contingency events are managed, thereby reducing the capacity limitations for REZs and facilitating larger REZs to be connected to the same transmission network. In turn, this could also result in lower overall costs to consumers by improving network utilisation.

Description of this incremental improvement

Under current arrangements, FCAS is normally procured globally in the NEM. The Rules do, however, permit AEMO to procure FCAS from within a specific region, rather than on a global basis.[94] AEMO will also procure FCAS on a regional basis at times when the interconnector between two regions is at a credible risk of separation.

Powerlink's proposal is to amend the NER and relevant subordinate instruments, to develop regional and sub regional FCAS to allow the potential for greater raise FCAS procurement.

AEMO could procure FCAS on a regional basis or limit the amount of FCAS procured from a single region to increase the amount of FCAS procured in other regions. A higher amount of raise FCAS enabled would mean there would be higher levels of 'headroom' in the system. This would increase the potential generation capacity in REZ developments and enable increased utilisation of the network connection. More localised arrangements for FCAS would value the trade off between higher raise FCAS and the cost savings from the development of more scale efficient connection infrastructure. Such requirements could be dynamic, trading off the cost of FCAS and savings in the energy market to allow greater credible generation contingency sizes.

Powerlink notes that a less complex and possibly transitional arrangement may be to reassess the maximum credible contingency size on a regional or sub regional basis periodically until a full market co-optimisation could be implemented.

We are considering whether there is value in operationalising regional procurement of FCAS more broadly, and are interested in stakeholder feedback on this approach.

How would this incremental improvement address the problem?

Routine procurement of FCAS at a regional level could support improvements to reliability by delivering a more immediate and seamless response to sudden and unexpected changes in VRE output. It would also increase the likelihood that the power system could be maintained in a secure operating state. This is because overload capacity on interconnectors would be less likely to be utilised.

The development of regional FCAS markets and increasing the amount enabled at times of high REZ generation would likely be associated with reduced transmission infrastructure requirements. As discussed above, improving network utilisation could also result in lower costs to consumers. Given the potential for delays in network build, Powerlink further considers that this would also enable a faster energy system transition.

The Commission is seeking stakeholder views in its assessment of this incremental improvement

94 Indeed, AEMO procures FCAS regionally during instances of islanding.

The Commission is seeking stakeholder views in whether there is merit in progressing a change to the Rules to formally require the marker operator to undertake routine procurement of regional FCAS.

Our initial assessment is that formalising arrangements related to the procurement of regional FCAS in the Rules would likely align with our assessment criteria. This would support improvements to reliability by likely increasing the ability of the power system to be maintained in a secure operating state. It also allows for flexibility in AEMO's processes, supporting AEMO to procure regional FCAS where it is more efficient and beneficial to do so. It is a relatively simple approach to implement and would allow for greater transparency by formalising a process that AEMO already undertakes (in instances of islanding).

In looking at the costs, while there may be potentially increased administrative costs for AEMO in operating the markets for regional FCAS and there is the potential for higher FCAS costs in the short-term due to shallow regional FCAS markets, we would anticipate that markets would deepen over time due to competitive pressures and these costs would moderate. Further, we note that any increased costs would be offset by having more scale efficient REZ developments and transmission infrastructure, lowering network costs for consumers and facilitating the transition. This allows for the existing network infrastructure to be used more efficiently, rather than relying on an increase of network build.

The Commission notes that there may be some risks associated with this incremental improvement with regard to market power. FCAS markets are currently somewhat concentrated and are therefore vulnerable to the exercise of market power. Procurement approaches would need to carefully consider the competition implications of regional procurement. However, our initial view is that the benefits may outweigh the costs.

The Commission welcomes views on this option and whether stakeholders agree that, in consideration of the risks and costs above, there remains value in formalising arrangements for the regional procurement of FCAS.[95]

95 The Commission also notes a rule changes request was lodged by Grids Energy relating to efficiency improvements in central dispatch related to contingency FCAS. This has not yet been initiated. When this is initiated, it will build on any considerations of Powerlink's proposal and considerations in this rule change request.

A BACKGROUND

A.1 About the rule change requests

A.1.1 Iberdrola Australia (previously Infigen Energy) — Operating reserves markets (ERC0295)

On 19 March 2020, the AEMC received a rule change request from Iberdrola (previously Infigen Energy) which sought to amend the NER to introduce a dynamic operating reserve market to operate alongside the existing energy and FCAS markets. The proposed operating reserve market comprises a dispatchable, raise-only service procured similarly to contingency FCAS services in real-time and co-optimised with the other energy market services.

The request proposes that this market would procure reserves 30 minutes ahead of time (with a 15-minute call time) to align with the requirement to return the system to a secure operating state within 30 minutes.

A.1.2 Delta Electricity — Introduction of ramping services (ERC0207)

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 offer stacks in response to predictable, daily, high rates of change from solar ramping up and down.

Delta Electricity proposes this service:

- be procured from dispatchable in-service generators
- reflect 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, and
- participants in this service would not be prevented from bidding into the other FCAS markets as long as they can comply with the associated obligations of each.

A.2 Related developments

A.2.1 ST PASA rule change

On 5 May 2022, the AEMC made a more preferable rule change to amend the ST PASA. The final rule provides a specific objective for ST PASA and introduces principles that are linked to the objective to guide AEMO as it administers ST PASA. This framework will enable AEMO and market participants to work together to decide on the appropriate information to be included in ST PASA.

The ST PASA rule change requires AEMO to publish:

- available capacity for individual scheduled generating plant and wholesale demand response units
- PASA availability for individual scheduled generating units, scheduled loads, scheduled network services and wholesale demand response units

- generator availability information for each unit and station, on a dispatchable unit identifier (DUID) basis.

Currently, AEMO publishes aggregate generating unit availability and PASA availability for each region. The rule change highlighted issues in these arrangements with information asymmetry between participants with large generation portfolios and participants with small generation portfolios, issues regarding generator availability and power system security and inefficient scheduling decisions made by participants.

This enhanced granularity of ST PASA outputs with generator availability at the DUID level will increase transparency and facilitate more efficient market outcomes. Furthermore, this will align ST PASA with MT PASA which already reports at the DUID level. This will better inform the market of generation availability and allow market participants to make better decisions regarding scheduling planned maintenance and expected reliability and security conditions.

The rule commences 31 July 2025 and requires AEMO to publish the ST PASA procedures by 30 April 2025. This rule changes forms part of a broader review into PD PASA and ST PASA currently being undertaken by AEMO.[96]

A.2.2 Energy adequacy assessment projection (EAAP)

The EAAP forecasts electricity supply reliability in the NEM over a two-year outlook period. The report provides information on the impact of potential energy constraints, such as water storages during drought conditions or constraints on fuel supply for thermal generation, on supply adequacy in the NEM.

The EAAP complements AEMO's other reliability assessments, such as the MT PASA and the ESOO. AEMO must publish an EAAP annually and as soon as practicable after becoming aware of any new information that may materially alter the most recently published EAAP.[97]

Under the EAAP's data collation process, all scheduled generators in the NEM are required to submit information to AEMO regarding the effect of energy supply limitations on their production outputs. This data provides a broad assessment of impacts on supply and reliability in the NEM.

Updates to the EAAP

Current scenarios specified in the EAAP guidelines predominantly relate to drought situations, however, clause 3.7C of the NER allows AEMO to consider other situations such as gas, coal, or diesel shortfalls. AEMO notes that energy limits relating to coal and gas availability are emerging as a material source of reliability risk in the NEM, having been a contributor to the market suspension event in June 2022. As a result, AEMO consulted on guidelines and methodologies to improve the consideration of thermal fuel energy limits, that will better inform future EAAP publications.

96 AEMO, 2023, ST PASA replacement project, https://aemo.com.au/en/initiatives/trials-and-initiatives/st-pasa-replacement-project.

97 Clause 3.7C(d) of the NER.

In the 2022 EAAP, AEMO included analysis that looked at the impact of energy limits in the NEM during the June 2022 period to help highlight that tight energy balances do occur and these types of scenarios are not represented in the current EAAP guidelines or the Guideline to Energy Limitation (GELF) data collection.

The new guidelines, published March 2023, allows for additional inputs and model changes to appropriately understand the risks of energy limits, and to effectively and efficiently model the impact of energy limits as required by NER 3.7C.

A.3 RERT

A.3.1 RERT is used as a safety net in the event the market fails to maintain the reliability standard

The RERT is a function conferred on AEMO to maintain power system reliability and system security using reserve contracts. AEMO continuously assesses whether forecast reliability and security is outside a relevant NEM standard. If it observes this and it considers there is no market resolution to it, then AEMO may choose to procure reserve. The trigger for the activation of reserve depends upon the lead time required to activate the reserve and the nature of the reserve shortfall.[98]

Under the RERT framework, AEMO secures contracts for emergency out-of-market reserves from providers, which can be activated (or pre-activated) upon request. These providers are grouped into short-notice, medium-notice, and long-notice providers:

- Short-notice providers are contracted for three hours to seven days. These providers receive compensation when reserves are required based on prices agreed upon appointment.
- Medium-notice providers are contracted for seven days to ten weeks. These providers negotiate prices if and when reserves are required.
- Long-notice providers are contracted for ten weeks or more via invitation to tender. Under the ESB's interim reliability measures, the long-notice RERT has been replaced by a mechanism that allows out of market reserves to be procured for up to three years, where an exceedance of the interim reliability measure has been forecast for two out of the three years including the first year and following consultation with and approval from the relevant Energy Council Minister of directly impacted states and/or territories. This is intended to remain in place until March 2025.

AEMO maintains a panel of RERT providers that can provide short notice and medium notice reserve if required and for whom technical details are pre-agreed. There is no panel for the long-notice RERT; rather, contracts are signed following the close of a public tender process. [99]

98 AEMO, 2023, RERT, https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert

99 AEMC, 2019. Enhancement to the reliability and emergency reserve trader rule 2019, https://www.aemc.gov.au/sites/default/files/2019-05/Final%20Determination.pdf.

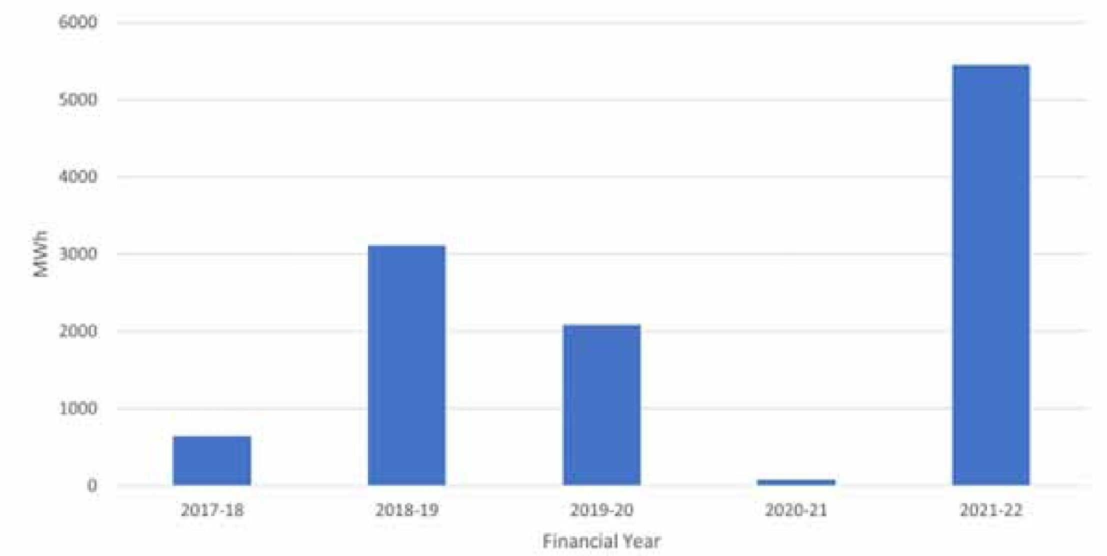
A.3.2 Accessing RERT can be costly

Interventions in or actions taken out of the market can be costly. For example, AEMO dispatched RERT on three occasions in NSW and two occasions in Victoria in 2019-20[100] and on two occasions in Victoria in 2018/19.[101] AEMO publishes cost estimates for exercising RERT, including the cost of compensating providers for their availability, pre-activation and activation and the cost inefficiencies associated with market intervention. In 2019-20, the cost estimate was $40.6 million[102] and in 2018/19, $34.5 million.[103]

A.3.3 Recent RERT activates and reliability directions

Figure A.1 outlines RERT activates between 2017-18 and 2021-22.

Figure A.1: **RERT reserves activated**



Source: Reliability Panel analysis of AEMO data

RERT activation escalated during the winter crisis of 2022, as outlined below.

BOX 9: RERT ACTIVATION DURING THE WINTER CRISIS OF 2022

The recent Reliability Panel's Annual Market Performance Report discussed the winter crisis of 2022 and highlighted the many and varied challenges facing the NEM (also recognised in AEMO's technical advice, section 3.1.3).

The Administered Price Period (APP) and market suspension event that occurred between 12

100 AEMO, RERT quarter Q2 2020 report and RERT end of financial year 2019-20 report, August 2020, pp. 5-6.

101 AEMO, RERT report for 2018-19, 2019, p. 1.

102 AEMO, RERT quarter Q2 2020 report and RERT end of financial year 2019-20 report, August 2020, p. 7.

103 AEMO, RERT report for 2018-19, 2019, p. 1.

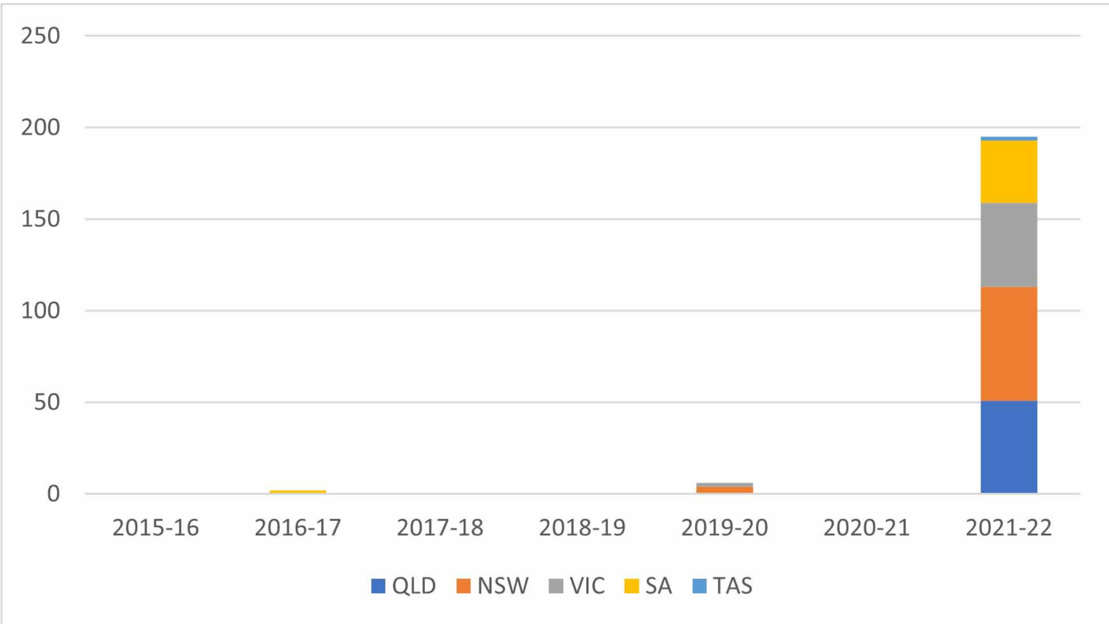
June 2022 and 24 June 2022 was an extreme event that arose out of a confluence of planned and unplanned thermal outages, low VRE generation periods, high customer demand, high commodity prices, and the level of domestic price caps.

Despite the challenges in June 2022, load shedding was avoided and customers maintained a reliable supply. This was the result of the extraordinary efforts of AEMO that issued directions, activated the RERT, facilitated outage cancellations, contracted for additional reserves and worked with industry and market bodies to maintain a reliable supply to customers during this volatile period.

Source: The Reliability Panel's Annual Market Performance Review 2021-22

AEMO's directions for reliability in the period 2015-16 to 2021-22 are outlined below.

Figure A.2: Directions for reliability



Source: AEMC's Reliability Panel analysis of AEMO data

A.4 Further details on power system terminology

A.4.1 VRE Ramps

Appendix C of AEMO's Renewable integration study (RIS) breaks VRE ramps into upward and downward ramps:

- An **upward VRE ramp** is where the net output from all VRE resources increases over an interval (that is, over five minutes or one hour). An upward VRE ramp may be met by an equivalent upward ramp in underlying demand or reduction in output from scheduled generation to maintain the supply-demand balance. Downward flexibility in the scheduled fleet can be achieved by turning online scheduled or semi-scheduled generation down or off (subject to ramp rates) and may be facilitated by increasing exports or decreasing imports from the region experiencing the upward VRE ramp.

- A **downward VRE ramp** is where the net output from all VRE resources decreases over an interval. A downward VRE ramp may be met by an equivalent downward ramp in underlying demand or an increase in output from scheduled generation. Upward flexibility in the scheduled fleet can be achieved by turning online generation up (subject to ramp rates) or instructing offline generation to turn on (subject to start-up times) and may be facilitated by decreasing exports or increasing imports to the region experiencing the downward VRE ramp.

A.5 Features of an operating reserve market

The following section outlines the key features of an operating reserve market, as outline in the working model provided in AEMO's technical advice.[104]

A.5.1 Provision of reserves would be centralised in an operating reserve market

Under this working model, AEMO would arrange for the commitment of availability from participants in advance of real-time, with procurement of reserves likely being co-optimised with the energy and FCAS markets.

Reserves could be procured every five minutes to be dispatched as energy at some point in the future (ahead of real-time). This could be from five minutes in the future up to several hours. This would aim to physically 'pre-position' the generation fleet so that there is sufficient capacity in reserve to respond to expected and unexpected changes in net demand.

AEMO would, at any point in time, determine the level of operating reserves to be procured. While the approaches to doing this are varied, one option would be to set the volume and price of reserves dynamically based on an 'operating reserve demand curve' (ORDC) that reflects the value consumers place on having capacity in reserve. This could incorporate the value and probability of lost load.

Procurement of reserves could also be tied to FUM thresholds, LOR 1 or LOR 2 declarations or some other trigger.

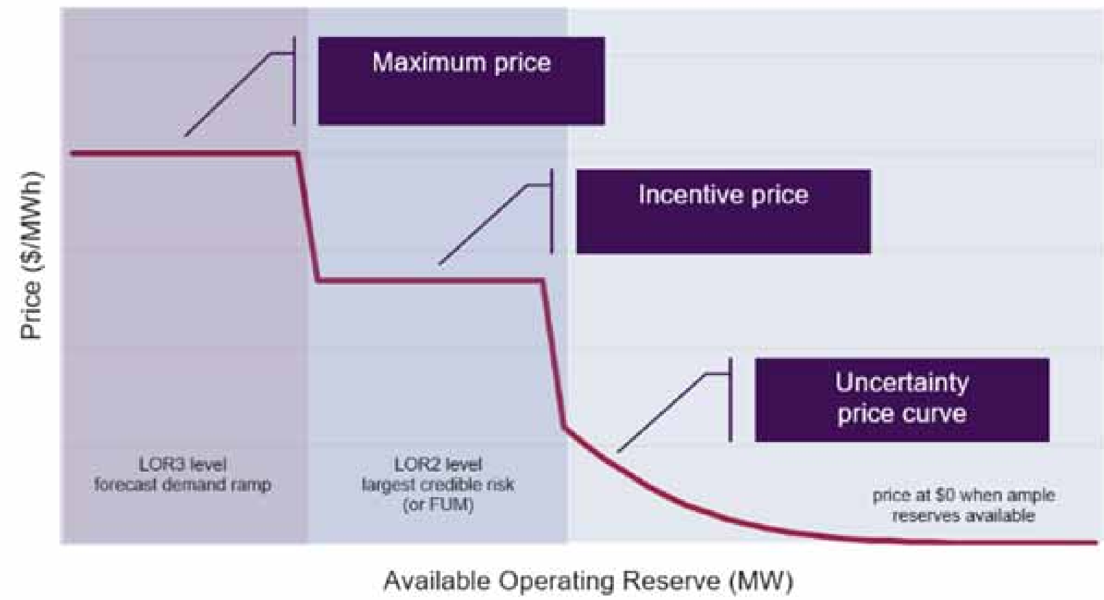
AEMO's technical advice provides further details related to the potential design of an operating reserve market, with AEMO recommending as a starting point a hybrid approach with robust compliance that considers the value of customer reliability and integrates with existing intervention frameworks.[105]

The example ORDC outlined by AEMO in its technical advice is provided below in Figure A.3

104 For more information see https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf.

105 AEMO's Technical Advice https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf.

Figure A.3: **Example operating reserve demand curve**



Source: AEMO, Operating Reserve Design, November 2022. Available from: https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf

The curve reflects AEMO's intervention framework and the incremental value of avoiding out-of-market actions according to uncertainty and the probability of lost load. The three prices described in Figure A.3 are defined below, consistent with AEMO's technical advice.

1. Maximum price: Minimum reserve requirements established to avoid lost load (currently the LOR 3 threshold for load-shedding when reserve capacity is at or below zero). This level of operating reserve could theoretically reference the value of customer reliability (VCR) or a similar reflective figure, less the maximum price cap (MPC) which participants would receive in the energy market if reserves were to fall below zero.
2. Incentive price: the price to bring reserves into the market, referencing the existing LOR 2 threshold when reserve capacity falls below the size of the largest credible risk.
3. Uncertainty price: Uncertainty pricing constructed via the probability curve of lost load (for example through historical operational demand uncertainty), reflecting the incremental value of avoiding out-of-market actions for higher reserve levels and allowing the procurement of additional reserve to appropriately manage system risk above minimum requirements when efficient to do so.
4. Operating reserve prices equal to zero when there is ample provision.

The operating reserve market price and quantity would be set by the intersection of the supply curve (the offer stack) with the demand curve. When there is ample reserve available (to the right), the supply curve would intersect with the demand curve at $0, and so the price would be zero. This calculation of offers of reserves may include energy spot market offers in pre-dispatch above forecast demand with care taken to avoid double counting.

Offers into the operating reserve market would be incorporated into the ST PASA, and in turn, the forecast for reserves.

A.5.2 How an operating reserve market could work in practice

A market participant could, for a given dispatch interval, offer its capacity (simultaneously) in up to ten price bands in each market to provide energy, FCAS, and 'reserve'.

AEMO would co-optimise offers for each service in that dispatch interval, and:

- dispatch energy in MW to meet demand
- enable capacity in MW to be capable of responding as FCAS
- enable capacity in reserve in MW, which is limited to the additional capacity that can be provided in a future dispatch interval.

The obligation on energy enabled as 'reserve' would to be capable of being dispatched as energy in a future dispatch interval, with the future period determined by the specific market design adopted. This could range from five minutes up to several hours.

If the supply/demand balance tightens:

- the energy spot price would increase as additional resources are dispatched to meet demand (some of which would likely have been enabled as reserves in previous intervals), and
- other resources (uncleared in previous intervals) would be enabled as reserves, likely at a higher price to reflect the short-run costs of the next MW of reserve.

This process would occur on a rolling basis, aiming to position capacity ready to respond to changes in net demand in a future dispatch interval. An operating reserve market would therefore aim to procure sufficient reserve capacity available to address increases in net demand future dispatch intervals, accounting for uncertainty.

A.5.3 Costs could be recovered by implementing causer-pays arrangements

The model could operate on a causer-pays basis. Under this model, the causers of demand and generation uncertainty would be required to cover the cost of needed reserves. This could provide incentives for participants to minimise their contribution to the need for reserves, even if they are not bidding into the operating reserve market itself.

In its technical advice provided in support of the AEMC's consideration of these rule change requests, AEMO outlined relevant cost recovery principles for an operating reserve market along with several cost recovery options that could be considered. AEMO's advice indicated that:[106]

> The stepwise construction of the proposed ORDC may allow for the costs associated with each step of the ORDC to be allocated to relevant causer groups, for example the component associated with forecast demand ramp being allocated to consumers, with uncertainty components being allocated across causer groups including the relevant

106 AEMO's Technical Advice, https://www.aemc.gov.au/rule-changes/operating-reserve-market, p. 12.

> technology types.

And further conveyed that:

> There are potential linkages of cost recovery with the Scheduled Lite reform program of the ESB Post-2025, in particular that participation in Scheduled Lite may allow for an opportunity to reduce exposure to Operating Reserve costs. Providing additional visibility of forecast demand and supply through Scheduled Lite can reduce uncertainty and hence the need for operating reserve.

Whichever model of cost recovery is pursued, costs recovered from causers would be passed on to market customers, which are ultimately paid for by consumers.

B SUMMARY OF STAKEHOLDER FEEDBACK

B.1 Stakeholder feedback on the Commission's previous directions paper

The AEMC published a directions paper on the reserve services rule changes on 5 January 2021.[107] The paper invited stakeholder feedback on:

- the power system need for reserves and the materiality of the need for a new operating or ramping service as the power system transforms.
- options to address variability and uncertainty on the power system, including:
  - incremental improvements to current arrangements
  - four new reserve service market options (see appendix B.5 below).

Submissions closed on 11 February 2021. The Commission received a total of 23 submissions.

B.2 Overview of stakeholder feedback

Stakeholder feedback received on the reserve service rule changes was mixed, with some stakeholders supporting a new operating or ramping reserve service and others maintaining a new mechanism is not required. Three key themes emerged from the responses:

1. Stakeholders were divided on the need for a new reserve service is, and whether the need is material enough to implement a new service.
2. There was significant support for incremental improvements to current arrangements.
3. There is no clear consensus on which option is best, but some themes emerged.

These themes are further explored in the following sections.

B.3 Stakeholders were divided on the need for a new reserve service

The key issue explored in the previous directions paper was characterised to stakeholders as an increased risk of insufficient in-market reserves being available to meet net demand, due principally to forecast uncertainty and net demand variability as the penetration of VRE increases. There was little agreement on the nature of this issue and whether it manifested in the investment or operational timescales.

Many stakeholders considered that the current market supported by government intervention is already driving investment in dispatchable capacity.[108]Variability and uncertainty were considered by many stakeholders to be issues, with some saying a new service is needed and others saying more work is needed before this conclusion can be made.[109]

107 AEMC, Directions paper reserve services in the national electricity market, 2021, https://www.aemc.gov.au/sites/default/files/2021-01/Reserve%20services%20directions%20paper%20-%205.01.2021%20-%20FINAL.pdf

108 GE Hydro submission https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_ge_hydro_-_20210208.pdf, Origin submission https://www.aemc.gov.au/sites/default/files/documents/rule_change_submissions_-_erc-295_-_origin_energy_-_20210212.pdf

109 ERM Power submission https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-

Some stakeholders were not sure a new service is needed given other potential changes under consideration such as the resource adequacy mechanisms under review including the T-3 ministerial lever for the Retailer Reliability Obligation.[110]

B.4 There was significant support for incremental improvements to current arrangements

A range of incremental improvements was proposed to address the issues or complement a reserve service. This included improving the accuracy of net demand forecasts, publishing better information, pursuing market and system enhancements, integrating distributed energy resources (DER), and adapting system definitions.[111]

Stakeholders showed clear support for improvements to forecasting and market information to help the market respond to uncertainty (e.g., PD PASA). [112]

There was more mixed support for other incremental changes, with some wary of the costs of some market and dispatch changes.[113]

Some stakeholders considered multi-period optimisation would be costly and unwind the benefits of a 5-minute settlement.

B.5 There was little agreement on the best option but some themes were emerging

Four reserve service market design options were proposed, including co-optimised and separate markets which procured reserve capacity over varying timescales. Specifically, the four reserve service market design options were:

- co-optimised operating reserve procured over a five-minute time horizon
- co-optimised operating reserve procured over a 30-minute time horizon
- callable operating reserve
- ramping commitment market.

_erm_power_-_20210211.pdf.

110 For more information see https://esb-post2025-market-design.aemc.gov.au/resource-adequacy-mechanisms-and-ageing-thermal-retirement#what-happens-next.

111 Distributed generation is a term used when electricity is generated from sources near the point of use instead of centralised generation sources from power plants. DER refers to often smaller generation units that are located on the consumer's side of the meter.

112 EUAA submission https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_energy_users_association_of_australia_-_20210211.pdf, AEC submission https://www.aemc.gov.au/sites/default/files/document/rule_change_submission_-_erc0295_erc0307_-_aec_-_20210211.pdf.

113 Enel X submission https://www.aemc.gov.au/sites/default/files/2021-02/Rule%20Change%20Submission%20-%20ERC0295%20%26%20ERC0307%20-%20Enel%20X%20-%2020210216.PDF.

Most stakeholders considered co-optimising a reserve service with energy and FCAS will have benefits. [114] There was no clear consensus on whether procurement over a five-minute or 30-minute time horizon is best. The lack of clarity reflects that some consider that the need is to promote investment while others consider that the need is to schedule reserves in operational timeframes.

114 GE Renewable Energy https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_ge_hydro_-_20210208.pdf, Tesla https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_tesla_-_20210211.pdf, Snowy Hydro https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_snowy_hydro_-_20210211.pdf, UNSW CEEM https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0295_erc0307_-_unsw_collaboration_on_energy_and_environmental_markets_ceem_-_20210211.pdf.

C MODELLING

C.1 Understanding the response of future potential generating fleets to energy market shocks

The Commission has undertaken market dispatch modelling to inform the Commission's assessment of the reserve services rule changes.

The Commission recognises that this modelling was undertaken in 2021 and because of this, a number of key market events that have occurred since then (e.g. the APP and market suspension) have not been taken into account in the results. We consider that this modelling still provides useful and valuable analysis that contributes to a better understanding of the future direction of the power system. However, we are interested in stakeholder views on whether an update to the model would be valuable for the draft determination.

The market dispatch modelling tests how various generating fleets may respond throughout a single day when exposed to significant shocks and unforecast events. Generating fleets from three regions are tested, both in their current state and a wide range of potential future development pathways. The modelling results provide useful insights into the relationship between variability and uncertainty, and the physical capability of various fleets to meet demand throughout the day.

The modelling sought to answer the following questions:

- In what circumstances may there be value for customers in introducing an operating reserve market (recognising that the outcomes of the modelling speaks principally to reliability and security value for consumers, and not to broader economic efficiency value)?
- What is the likelihood of these circumstances arising in the NEM and in what timeframes would we expect to see them occurring?
- How does the nature of the problem inform the policy options?

C.2 Modelling approach

Initial approach

The initial scope of the modelling was to build a series of realistic future generation mixes based on the Victorian power system and expose them to a number of different events of a significant but reasonably foreseeable magnitude. The future generation mixes were based on AEMO's ISP scenarios. These fleets were then exposed (in the model) to the progressive loss of variable renewable (VRE) generation over the course of an hour or more. The fleets were given new forecasts every five minutes, throughout the evolving event, which was designed to reflect the way that real-world events such as changing weather conditions tend to unfold. For each combination of event and generation mix, the model did not show any instances where the fleet was incapable of ramping to meet the needs of the system. The findings from this initial approach were therefore limited, and the approach evolved to develop further and more informative data to feed into the rule change consideration.

Evolved approach

The evolved approach to the modelling exercise was to stress test the system in order to more clearly show the circumstances in which reliability and security concerns might emerge on the system. This involved developing a set of potential future generation fleets that represent the broadest range of potential outcomes (from very inflexible to very flexible), and exposing those fleets to a much more severe set of shocks that occurred over shorter periods of time (15 to 30 minutes). As will be discussed further below, this approach showed that for some fleets in some scenarios the modelled outcomes showed instances of insufficient reserves capable of ramping to meet the rapidly changing net demand needs of the system. This approach more clearly showed the relationship between severe net demand ramping events and fleet flexibility that may lead to reliability and security concerns.

The Commission consulted with industry stakeholders and market bodies on this iteration of the modelling. Following that consultation, and based largely on requested changes and further work from AEMO, the modelling was updated to include:

- the Queensland and South Australian regions,
- sensitivity testing to see how the fleet may respond if hydro resources were already generating (lower than gas in the merit order) when an uncertain event occurs,
- a new case scenario to test the largest sized potential forecast error (based on research presented in policy paper 2) occurring during or at the end of the evening net demand ramp and
- tested variations in the timing and size of the existing event scenarios.

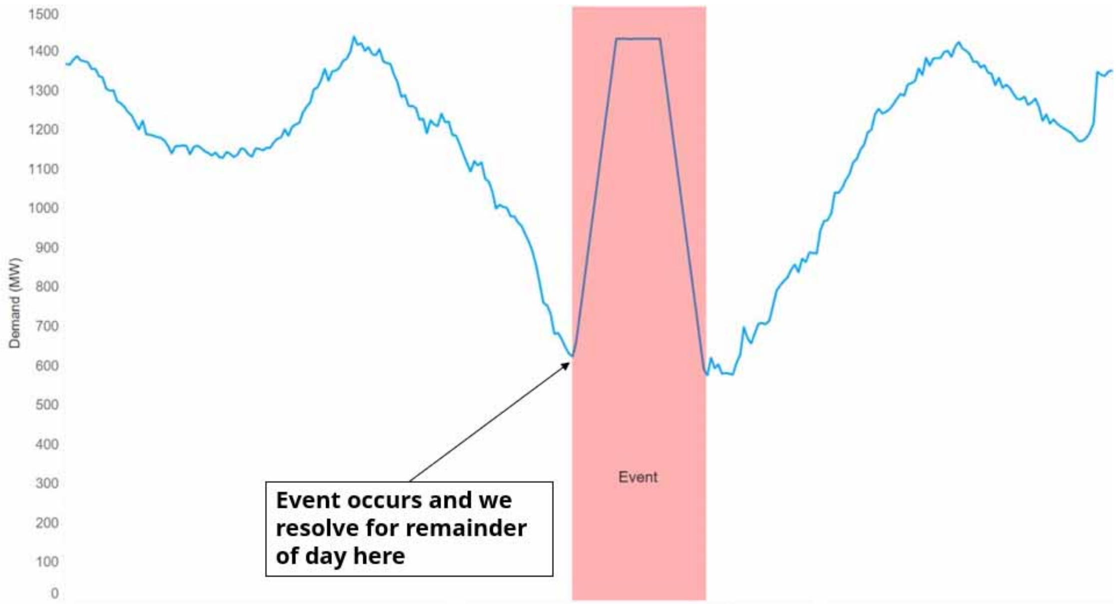
C.3 How the model works

The model looks at outcomes for a single region that has to deal with an unexpected event on a single day (rather than modelling outcomes over, say, a year or decade). It is an "optimisation model" (much like NEMDE) that optimises outcomes on that day based on the costs for the various technologies that make up the generation fleet. It analyses a day using a sequential process, meaning that each day is broken up into 288 five-minute dispatch intervals that occur one after the other. The model then solves for the optimal outcome throughout the day using the process outlined below:

- In the first dispatch interval a forecast is provided that sets the expectations for the rest of that day. The model takes that information and optimises the dispatch of the fleet in that interval based on the expected optimisation of the fleet to achieve supply and demand balance for the whole day at the lowest total cost.
- In each successive interval for the rest of the day the model runs a new optimisation, dispatching the fleet based on the expectations at that time (i.e. based on any revised forecast that has been provided).

This modelling approach is distinguished by its capability to account for uncertainty. As reserves would not be needed with perfect foresight, capturing the response of the power system to uncertainty was the critical functionality required of the model. This model introduces the element of uncertainty by adding a series of new forecasts throughout the occurrence of an event. As the model sequentially re-solves for the optimal outcome throughout the event, capacity that was positioned on the basis of earlier forecasts is forced to respond to the new power system needs as they rapidly unfold. In this way, the modelled power system is not able to prepare itself in advance, but must react as the uncertainty unfolds.

Figure C.1: Simplified example of model mechanics



Source: Endgame Economics

Figure C.1 demonstrates this concept. This diagram shows the energy demand over the course of the day. The demand forecast at the beginning of the day does not include the spike (red shaded area) which occurs at midday. At the beginning of the day, and in each subsequent dispatch interval, the dispatch is optimised for the expectations of the day. Those expectations are unchanged, until the event begins. As the event is not expected, it is not factored into the way the fleet has been positioned up until that point. When the event occurs in the middle of the day the system continues to re-optimise based on each new forecast. The decisions made in the dispatch intervals up until the time of the event have a large impact on how capable the system is to respond to the event.

This modelling helps us to understand the implications of future fleet makeup for the capability to respond to sudden shocks and uncertainties. Participants currently prepare for such uncertainties through their self-commitment of reserves to manage the risks they face in the energy market based on their own forecasts as well as information provided to them by AEMO. This modelling can therefore assist in the assessment of whether this approach is likely to remain sufficient, or whether the risks associated with the transition may warrant the introduction of new arrangements, such as an operating reserve service, that would change the behaviour of the fleet in the lead up to an event to ensure sufficient capacity is available to respond.

C.4 Regions

The model includes a series of single region power systems. Victoria, Queensland and South Australia are each modelled as single regions with no interconnection, with the exception that the Victorian system includes limited interconnection (Murraylink) to allow for some Hydro capacity to enter the region. These regions were selected because they represent a cross-section of the entire NEM that embodies the key risks that operating reserves may be designed to address (net demand uncertainty and fleet flexibility).

Victoria has a high penetration of inflexible brown coal plants, limiting the ramping capability of the state's generation fleet.

Queensland's scheduled generation is similarly inflexible due to its black coal fleet and relatively slow-responding gas fleet. The state is also at risk due to its high rooftop PV penetration that may be prone to weather-related uncertainty.

South Australia is exposed to relatively higher levels of net demand forecast uncertainty due to its proportionately larger VRE generation fleet.

Together these three regions capture the potential issues faced by the broader NEM. Other regions were considered less valuable to model.

To test the capability of each region to respond to a range of scenarios, each modelled region is exposed to events that occur on illustrative days. This approach reduces the computational complexity of the task by avoiding having to model every day for the next 15 years and allows for clear comparison between each region's response to the same event. Illustrative days were also used because most of the time the power system is operating normally and forecasts are accurate so uncertainty is low and operating reserves would have a low value. However, when events diverge from forecasts, operating reserves are valuable so using illustrative days allows the analysis to focus on those events.

C.5 Fleets

The modelling stress-tested the resilience of the power system to six scenarios consisting of unexpected losses of variable generation and increases in net demand. The generation fleet assumptions are critical to the development of a set of results that can inform our understanding of the ability of the fleet to provide reserves in the future. To achieve this, the model tests the performance of the current generation fleet, as well as five other fleets representing the bounds of potential future development of the power system.

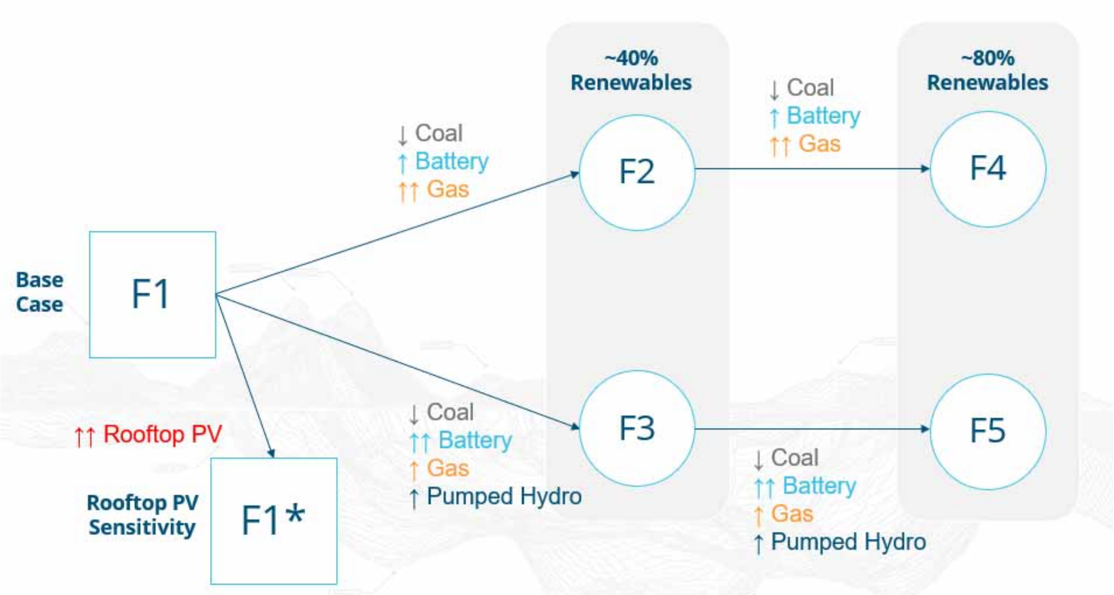
The fleets tested, and how they relate to one another, are shown in Figure C.2. The fleets are shown across three time horizons representing the present-day fleet and the periods of time that are approximately mid-transition (40% renewables fleets) and late in the transition (80% renewables fleets) to a power system dominated by VRE generation. Fleet F1 is the current fleet, and a further sensitivity (fleet F1*) added significant rooftop solar PV to this fleet to stress test the behaviour of coal generation under such conditions.

The future power system fleets diverge along two pathways that represent the "bookends" of potential flexibility of the system:

- **the inflexible pathway** - fleets F2 and F4 show how the power system might look if there is a significant development of new and relatively inflexible gas generation to provide firming around renewables. The new gas is assumed to be capable of starting up and generating within 30 minutes.
- **the flexible pathway** - fleets F3 and F5 show how the power system might look if there is a significant development of storage (large scale batteries and pumped hydro) to provide firming around renewables.

The flexible pathway is more closely aligned with the level of flexibility in the fleets envisaged by the ISP scenarios (whether central case or step change). It also appears that the current market signals are resulting in a preference for investments in highly flexible new generation, rather than inflexible.

Figure C.2: Fleet visualisation



Source: Endgame Economics

C.6 Scenarios

Six illustrative days (case studies) were used to test the response of the system to a wide variety of adverse events. Across the case studies, the type, magnitude and timing of the events change. In earlier runs of the modelling, the events on the system gradually worsened over an hour or more. In order to better test the capability of various fleets to respond to extreme circumstances of uncertainty, the events were adjusted to be more extreme in magnitude and to unfold over a period of 15 to 30 minutes.

The case studies are summarised below:

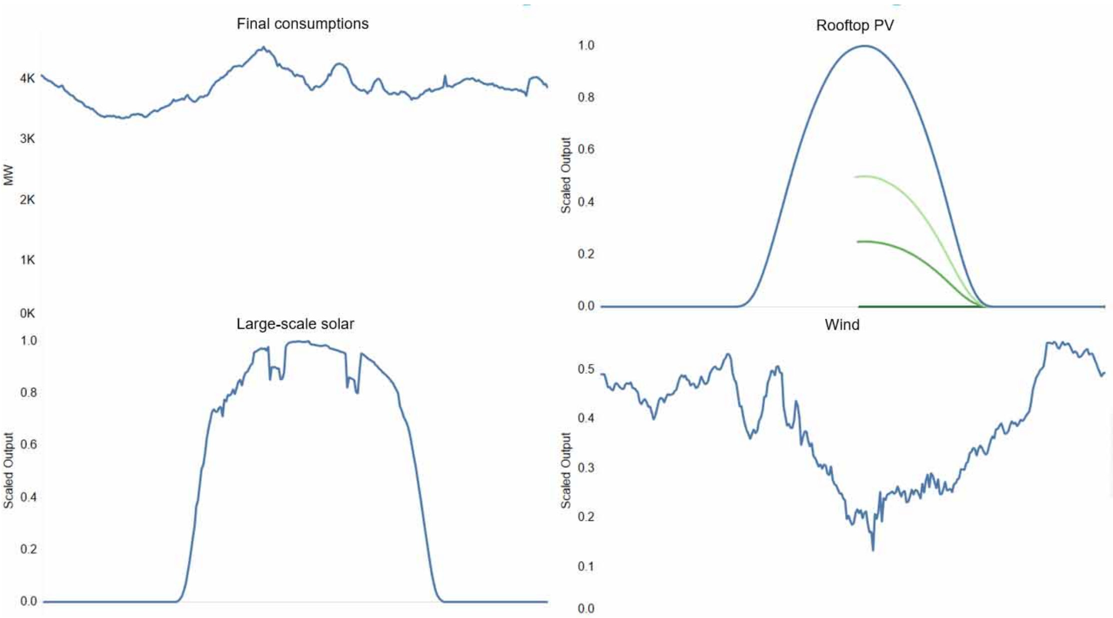
1. **Case 1 - Wind drops off during the evening ramp**. In this case, it is expected that wind will be fairly constant throughout the day and provide significant capacity during the evening. However, just as the evening peak is about to begin, the wind generation drops from approximately 80% of capacity to almost 0% of capacity over a 30-minute period.
2. **Case 2 - Loss of REZ during middle of the day**. In this case, the region loses nearly all the wind generation and large-scale solar over a 30-minute period in the middle of the day. This case loosely represents the impact of losing multiple renewable energy zones (REZs) and for this reason rooftop PV is not adversely impacted.
3. **Case 3 - Loss of PV on sunny, low demand day**. In this case, a low demand day is selected so fewer coal units are running. The rooftop solar in the region then drops to 0MW in a 15-minute period. This case was used as a bookend which can be compared with less severe events.
4. **Case 4 - Wind never comes**. In this case, the wind generation is forecast to ramp up into the evening peak so the system is relying on that. Then, just as the evening peak beings, instead of ramping up, the wind drops to 0MW in 30 minutes. This scenario is impactful for the behaviour and decision-making of storage assets which were not expected to be needed.
5. **Case 5 - Loss of PV on a moderate-high demand day**. This scenario resembles Case 3. However, this time it is a moderate-high demand day so the system needs more energy when the same event occurs and all the rooftop PV is lost in 15 minutes in the middle of the day. When compared to Case 3, this scenario highlights the behavioural impacts of different generation types choosing to switch on or off.
6. **Case 6 - Estimated maximum forecast error.** In this case, the region's energy consumption increases by the estimated maximum forecast error (developed with AEMO as per the analysis from policy paper 2) at or close to the evening peak. The region's solar is not available (because the sun has set) and the wind was forecast to drop to around 20% of output during the evening peak. While this level of forecast uncertainty would not occur when there is very little VRE output, this case does show how a system with very low reserve levels may respond to a large shock.

By way of example, Figure C.3 shows the forecast assumptions and changes to forecasts during Case 3. Each of the four graphs describe the course of a day (horizontal axis is 24 hours). The top left graph is the final consumption (total demand) which is the amount of power (in MW) at each 5-minute interval that must be supplied by the generating fleet throughout the day. That energy can be supplied by rooftop PV, large scale VRE or scheduled generation. The other three diagrams show the scaled output profile of rooftop PV, large-scale solar and wind (in % of output of the relevant fleet capacity). In Case 3, the rooftop solar in the region drops from 100% output to 0% output over a 15-minute period.

The forecast at the start of the day is shown in the blue lines. The uncertain event is shown in the green lines. At a certain point throughout the day the forecast for the output level of a technology type (in this case rooftop PV) begins to change, shown in the green lines. In this example the green lines show rooftop PV output dropping off in three successive five-minute periods (15 minutes). The top green line (light green) is the forecast for rooftop PV after 5-

minutes, where it has dropped to around 50% of its maximum output. The middle green line shows the solar output after another 5-minutes, where it is down to around 25%. The bottom green line (dark green) shows the solar output after another 5-minutes where the solar is now producing 0MW and is forecast to continue producing 0MW for the rest of the day.

Figure C.3: Example - Case 3: Loss of PV on a sunny, low demand day (VIC)



Source: Endgame Economics

Cases 1 to 5 are events that reduce the output of rooftop PV or VRE generation at different times. Case 6 however simulates the largest net-demand forecast error occurring at the worst possible time (the end of the evening ramp). This could not be achieved by reducing VRE output, and so this case is simulated by an increase in total demand (the top left graph) at the evening peak.

C.7 Model assumptions

A model is a set of formulae that makes decisions, based on the inputs provided to it, and which produces a set of outputs that can be interpreted. The inputs to the modelling are therefore critical to understanding and interpreting the outputs. AEMO provided significant input in the development and evolution of the assumptions and inputs, including discussions with AEMO’s operations staff. Key assumptions are detailed below:

- **Ramp rates** – the ramp rates used to model how quickly the output of a generating unit could increase or decrease were consistent with the AEMO ISP. Stakeholders provided us with input that these ramp rates are probably optimistic and do not reflect the real capability of the system. While we did not change this assumption, we took these views into account in interpreting the results.

- **50% starting storage** - The energy storage assets, including batteries and pumped hydro, began each of the modelled days with 50% of their storage capacity. This is a significant assumption so sensitivity analysis was conducted to understand the impact of this decision. While batteries start the day half-full, the model optimises their performance for the forecast over the single day. This means that at times the batteries may assume they have sufficient charge, past the time when spare generation is available to charge from, and then be subjected to an event which they have insufficient depth of charge to address. The interpretation of these results must be carefully considered in light of the likely real-world behaviour of storage capacity, which would need to take state of charge into account in managing risks and financial exposures (e.g. placing a higher value on stored capacity at times of increased forecast uncertainty or when region-wide storage capacity is at lower levels).
- **No interconnection** – Queensland and South Australia were each modelled as standalone regions with no interconnection in order to keep the model simple and the results conservative (because at times interconnection may be constrained). The only exception was for Victoria which has a limited amount of interconnection to allow for Hydro capacity to enter the region.
- **No demand response** – The model does not include any demand response or demand side participation. This means any supply/demand imbalances can only be addressed in this model by the generating fleet.
- **No security or intervention/backstop mechanisms in place** - The model does not include the use of any security frameworks, such as contingency or regulation frequency control ancillary services or the use RERT or other interventions.

These input assumptions were generally chosen in order to conservatively model the potential outcomes for each region. For most of these, the real-world circumstances would be different (i.e would have interconnection, demand response etc.) and real-world outcomes would therefore be different. These differences are taken into account in the interpretation of the results.

C.8 Model limitations

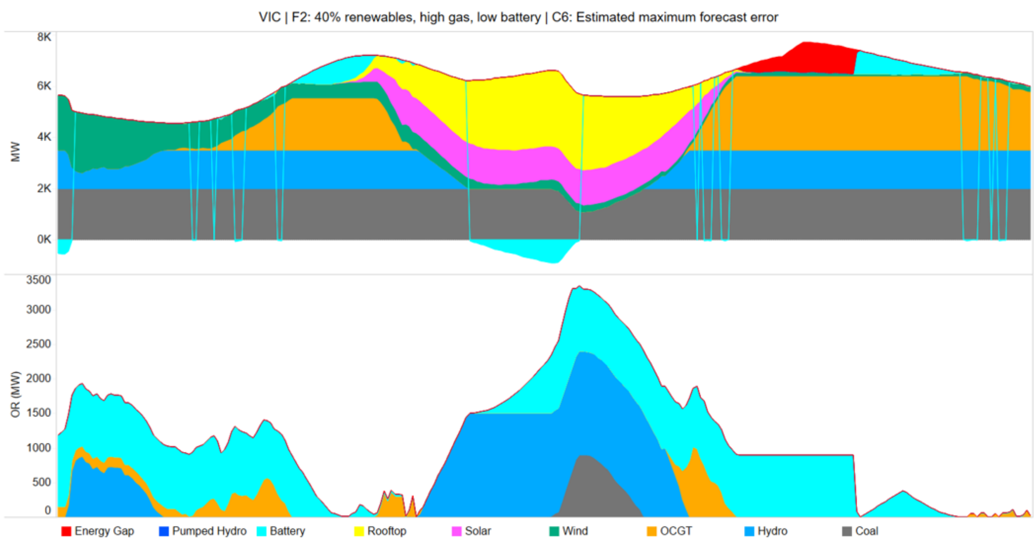
The key limitations and their impact on interpretation of the model's outputs are explained below:

- **Cost-based modelling** – This model is a cost-based model, rather than a price-based model. This approach uses the costs of each generating asset and optimally dispatches the entire fleet at the lowest total costs. In the model, behaviour is modelled using cost minimisation to meet the demand needs for the single day. However, this means that the model does not capture the role of prices (e.g. prices or the risk of price spikes) in driving participant behaviour. It is the risk of price spikes that underpins the self-commitment of reserves under current frameworks. This is not captured in this model.
- **Events are synthetic** – The evolution throughout each of the illustrative days is driven by simulated events. These events have been constructed to change over time to incorporate the element of uncertainty. Future events may not follow the structure and

patterns that have been assumed by the model. The deterministic foundation was used rather than basing the case studies on historical days because the exercise is designed to identify uncertainty in the future power system. The nature of uncertainty may change so using historical days could be misleading and make the results less robust.

- **Behaviour is assumed to be perfect** – The model captures uncertainty using forecasts that update every 5 minutes and those forecasts are subject to change. However, for each 5-minute period, the model optimises the dispatch based on the available information and assumes that the behaviour for each 5-minute period is perfect in order to meet the needs of a single day in isolation. In the real world, participants do not adhere to the least cost solution of the whole power system. The behaviour of participants is irregular and imperfect as decisions are influenced by a range of factors including contract positions, individual risk appetites and differing views of the future which all interact with uncertainty. This characteristic of the model has a significant influence on the state of charge of storage technologies (noted above) because it means they do not hold any additional capacity in storage to value the ability to respond to uncertainties, particularly those occurring late in the modelled day.
- **Power system is assumed to be fully operational** - The model considers that all generating units are available, and not out for maintenance or being cycled offline seasonally. It also assumes there are no binding network constraints to move power to load centres within a region. The power system is subject to these real-world constraints, and the results should be considered accordingly.

C.9 Modelling results and observations



Each of the model results is composed of two diagrams which describe the power system over a day. The vertical axis for both diagrams is energy capacity in MW and the horizontal axis is time (24 hours). The top diagram is the capacity that is dispatched as energy in MW to meet the total demand needs of the system over the course of the day. The bottom diagram is the level of operating reserves that are available at any point in time. Operating reserves in this case are defined as capacity (in MW) that is not dispatched as energy, but is available to be dispatched as energy in 30-minutes.

The capacity is shown by generation type that aligns to the generation fleet assumptions described above. VRE, including rooftop PV (yellow), solar (large-scale) (pink) and wind (green) are not scheduled generation so their capacity is not included as part of the bottom OR graph (however, economically curtailed VRE is highly dispatchable and therefore capable of providing reserves).

When batteries (light blue) or pumped hydro (dark blue) are charging, this is shown both as negative capacity on the top diagram and an increase in total demand that is met by other resources. Increasing stored energy increases the level of operating reserve. This can be seen in the above figure by the level of operating reserve provided by batteries (light blue) increasing after charging during the midday period. Open cycle gas turbines (OCGTs) (orange) are not shown as being in reserve when they are offline or operating at their generating limit, but are shown in reserve when they are turning on and can provide energy within 30 minutes, or when they are online and have headroom available.

Whenever the supply/demand balance cannot be met, it leads to an energy gap (red). A quirk of the model program is that an energy need that can be filled in part by storage (batteries or pumped hydro) will be shown as occurring before the storage capacity is used. See in the figure above how the energy gap (red) occurs before the flexible battery storage (light blue) is used to meet demand at the end of the day. This would of course not be expected to happen in the real world, where we would expect to see the energy storage being fully depleted before any energy gap.

C.9.1 Reserves across different time horizons

The power system needs reserves that are capable and available to be dispatched by the NEM dispatch engine (NEMDE) to ensure that supply can balance with demand in each five-minute interval across all time horizons. This modelling highlights how issues may arise across different time horizons. We have broken the different horizons into three categories to aid analysis and discussion:

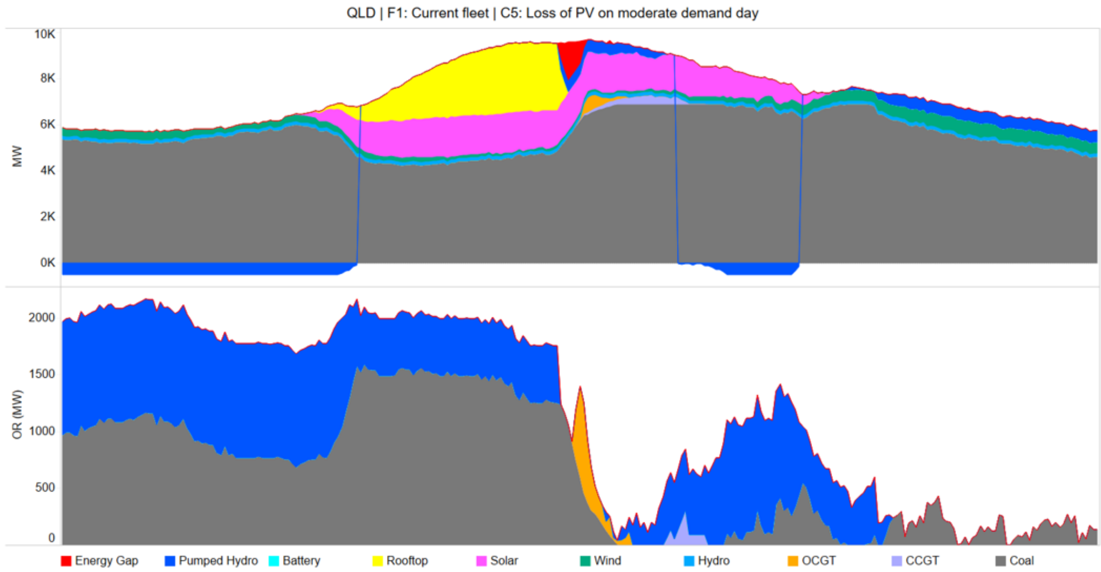
1. Flexibility in operational timeframes: five minutes to one hour
2. Availability over a day: 24 hours
3. Availability over multiple days: days/weeks

1. Flexibility in operational timeframes: five minutes to one hour

The power system needs reserves with the headroom and ramping capability to meet the supply/demand balance in the near future. The events simulated by the model all occur within a very short timeframe (15 to 30 minutes). This tests the level of reserves able to be dispatched as energy from the beginning of an event (i.e. in the first five-minute dispatch interval after the forecast has changed) until the system has rebalanced to provide the energy needs for the rest of the modelled day (which can be up to an hour after the beginning of the event). When the power system lacks flexibility, the fleet is unable to supply energy fast enough to meet the unexpected increase in the net demand profile. The fleet's ability to meet this need is constrained by start-up times, ramp rates and headroom across all generators that make up the fleet. An issue caused by a lack of fleet flexibility in operational timeframes is characterised by a short, sharp energy gap that occurs while the fleet repositions by starting up and ramping to meet net demand. The energy gap lasts as long as it takes for flexible plant to respond.

Figure C.4 shows a power system that lacks flexibility in operational timeframes. It shows the Queensland current fleet (F1) being exposed to a loss of all rooftop solar PV over a 15-minute period on a moderate demand day (C5). The top half of the diagram shows that the region's rooftop PV (yellow) drops from full output to 0MW over a period of 15-minutes. As the rooftop PV drops off, the reserves being supplied by coal (grey) are converted to energy. The drop in PV output, and consequent increase in net demand, occurs at a faster rate than the coal fleet can ramp up. During the time when the coal fleet is ramping up at its maximum rate the level of reserves provided by coal drops to 0MW, as shown in grey in the bottom half of the diagram below. With the coal generators unable to supply enough reserves, the OCGTs (orange) switch on. When they commit to provide energy, the level of reserves they provide spikes (shown in the orange in the bottom half of the graph), and then reduces as those reserves are converted into energy (shown by the orange area in the top half of the graph). Despite the entire fleet starting and ramping as quickly as it can, there is insufficient flexibility and headroom available to meet the net demand needs throughout the event. This leads to a short energy gap (red) shown in the top half of the diagram below. Once the coal and gas have enough time to ramp up, they cover the energy shortage and return the supply/demand balance.

Figure C.4: Queensland, F1, C5



Source: Endgame Economics

The consideration of operating reserves focuses on flexibility issues in operational timeframes. An operating reserve market would procure reserves available to convert into energy over a 5- to 30-minute period to address uncertainties in operational timeframes. With reference to the diagram above, an operating reserve service could aim to procure reserve capacity that is capable of being dispatched as energy to meet the rapid change in net demand needs. If this was the case, the modelled fleet would have been better positioned to meet demand and avoid the energy gap (red) if sufficient quantities of reserves were procured. In this case, at the time of the event around 2 GW of reserves were available and because the modelled event was so large, four or more GWs of reserves would need to have been procured to avoid an energy gap.

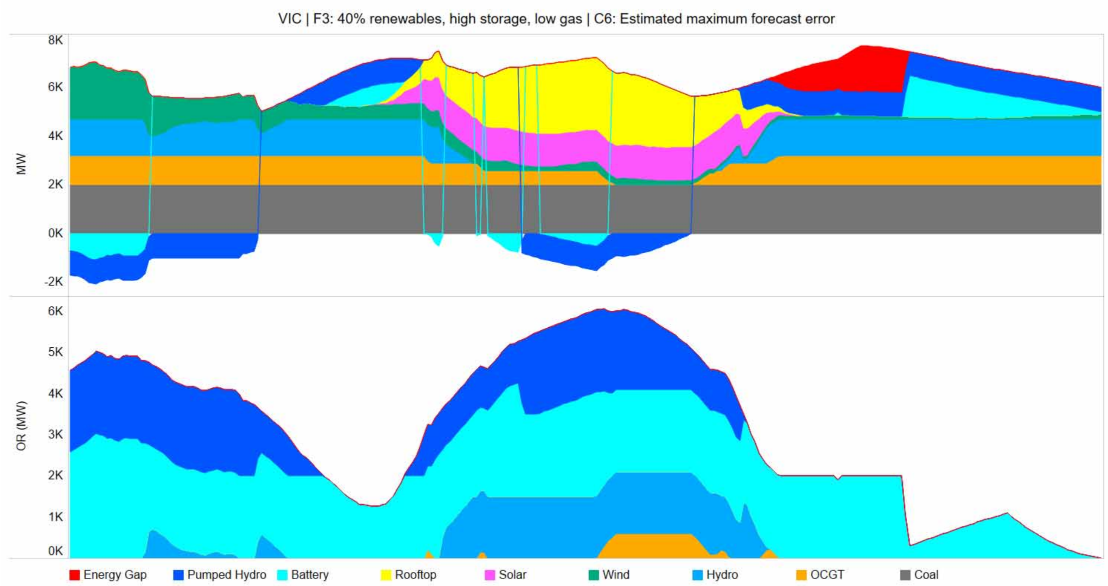
2. Availability over a day: 24 hours

The power system needs in-market reserves with the headroom and ramping capability to meet the supply/demand balance over the course of a full daily cycle. The NEM currently has a generation mix that is largely made up of scheduled thermal generation. These generators are generally able to run non-stop (given a stable fuel supply), which provides the system with enough capacity throughout the entire day. However, if these thermal generating assets are replaced by VRE firmed by storage that is energy (MWh) limited by its depth of charge, there is a risk that the fleet may at times not have sufficient energy stored to meet the total demand needs for the day.

These energy capacity issues are characterised by more extended periods where there is an energy gap. The fleet may have the operational flexibility to meet energy needs over a short period, but not the energy stored to meet needs over longer periods.

Figure C.5 shows a power system that lacks capacity to meet total demand over a 24-hour period. It shows the Victorian future 40% renewable fleet that has high storage and low gas (F3), being exposed to the maximum forecast error during a critical point in the evening peak (C6). During the event there is a shortage of energy without any VRE available to supply it. Energy storage is the only generation type that is available, but both the battery storage (light blue) and pumped hydro (dark blue) do not have sufficient charge to meet the requirements of the system. With all the storage depleted, an energy gap (red) emerges.

Figure C.5: Victoria, F3, C6



Source: Endgame Economics

An operating reserve market would procure reserves to position the fleet so it is capable of being dispatched as energy in the near future, say 5 to 30 minutes. This policy tool, however, is not well suited to addressing these longer-duration energy availability issues. Positioning the fleet for short-term flexibility would likely not ensure energy storage is sufficient to meet the needs of the system beyond the period of time contemplated by the reserve product procured.

3. Availability over multiple days: days/weeks

The system needs reserves with the headroom and ramping capability to meet the supply/demand balance over the course of days, weeks and beyond. Presently, the NEM's thermal generation mix provides reserves over a long duration (given a stable fuel supply). However, if the power system develops along the pathway of VRE firmed with storage technologies, there may be risks associated with these technologies having sufficient charge to manage extended periods with low renewables output (so called "VRE droughts").

As noted above, an operating reserve market is likely to not be well suited to addressing energy shortages that occur in the timeframe beyond the period contemplated by the reserve product procured.

C.9.2 Snapshot of results

Figure C.6, Figure C.7 and Figure C.8 show snapshots of the modelling results for each region. In these summary tables, a green square means there was no energy gap shown, a pink square means there was a relatively small energy gap shown, and a red square means a large or material energy gap was shown. Where there was an energy gap, consistent with the discussion above we have classified the nature of the issue as being caused either by a lack of flexibility in operational timeframes, or a lack of storage duration (or MWh) to serve energy needs over the course of the day.

Figure C.6: Victoria modelling results snapshot

Lack of flexibility	F1: Current Fleet	F2: 40% renew, high gas, low storage	F3: 40% renew, high storage, low gas	F4: 80% renew, high gas, low storage	F5: 80% renew, high storage, low gas	F1*: Current fleet + PV
C1: Wind falls during evening						
C2: Loss of PV around noon						
C3: Loss of PV on sunny day						Lack of flexibility
C4: Wind never comes		Lack of duration				
C5: Loss of PV on moderate demand day	Lack of flexibility	Lack of flexibility	Lack of flexibility			Lack of flexibility
C6: Max forecast error (same as C7)	Lack of flexibility	Lack of duration	Lack of duration	Lack of duration	Lack of duration	Lack of duration
C6 + Hydro Sensitivity		Lack of duration	Lack of duration		Lack of duration	

Source: Endgame Economics

Figure C.7: Queensland modelling results snapshot

	F1: Current Fleet	F2: 40% renew, high gas, low storage	F3: 40% renew, high storage, low gas	F4: 80% renew, high gas, low storage	F5: 80% renew, high storage, low gas	F1*: Current fleet + PV
C1: Wind falls during evening						
C2: Loss of PV around noon						
C3: Loss of PV on sunny day	Lack of **flexibility**					Lack of **flexibility**
C4: Wind never comes		Lack of **flexibility**		Lack of **flexibility**		
C5: Loss of PV on moderate demand day	Lack of **flexibility**	Lack of **flexibility**	Lack of duration	Lack of **flexibility**		Lack of **flexibility**
C6: Max forecast error (same as C7)	Lack of **flexibility**	Lack of **flexibility**				Lack of **flexibility**

Source: Endgame Economics

Figure C.8: South Australia modelling results snapshot

	F1: Current Fleet	F2: 40% renew, high gas, low storage	F3: 40% renew, high storage, low gas	F4: 80% renew, high gas, low storage	F5: 80% renew, high storage, low gas	F1*: Current fleet + PV
C1: Wind falls during evening	Lack of **flexibility**					
C2: Loss of PV around noon	Lack of **flexibility**					
C3: Loss of PV on sunny day	Lack of **Flexibility**			Lack of **Flexibility**		Lack of **Flexibility**
C4: Wind never comes	Lack of **flexibility**			Lack of **Flexbility**		Lack of **Flexibility**
C5: Loss of PV on moderate demand day	Lack of **Flexibility**			Lack of **Flexibility**		Lack of **Flexibility**
C6: Max forecast error (same as C7)						

Source: Endgame Economics
Note: South Australia has already passed 40% renewable penetration so F2 and F3 were not included in the modelling results

What can be seen at a high level in these tables is that generating fleets with higher levels of storage are more flexible in operational timeframes, but have increased risks of energy storage duration issues. Conversely, fleets with higher levels of inflexible gas generation are less flexible in operational timeframes, but are better able to serve energy needs over longer durations. This will be discussed in more detail below with reference to specific examples and the capabilities of particular technologies.

C.9.3 Key takeaways for the current power system

The modelling demonstrates that the current system (fleet F1) is resilient on balance to issues arising over various timeframes. There does not appear to be significant operational flexibility or longer duration capacity issues arising from changes in VRE/net demand with the current mix of generating resources in Victoria, South Australia and Queensland. This assessment should also hold for New South Wales and Tasmania, which were not modelled because they have more flexibility in their generating fleets. With its significant reliance on coal generation, the current fleet is unlikely to be suitable to meet the changing needs of a future system with high renewable penetrations.

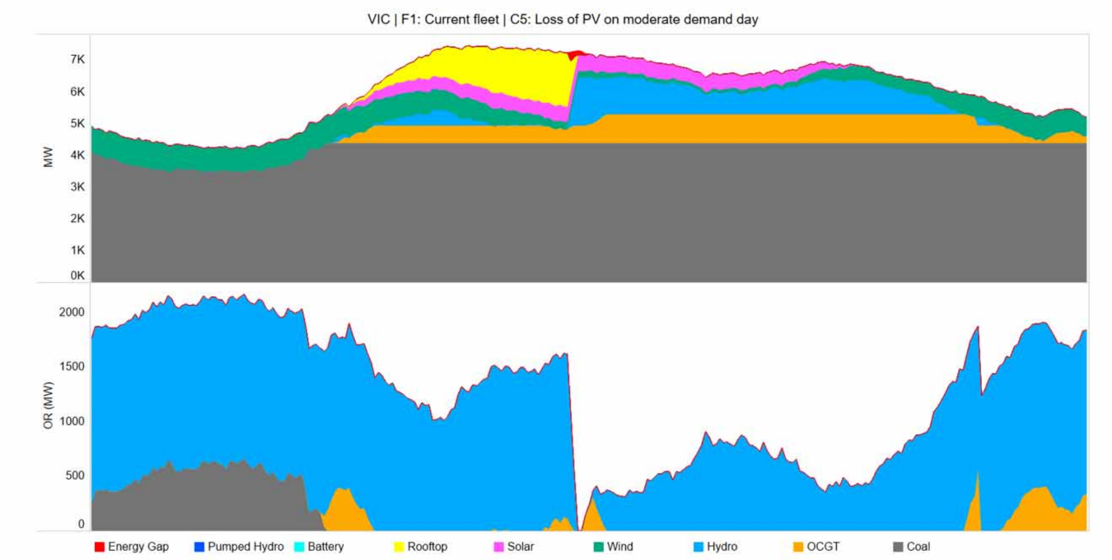
This section discusses the modelling results for the current mix of generating resources on the system and considers how well the current fleet is placed to meet the potential future needs of the system. We conclude, broadly, that the generating fleet will need to evolve to maintain reliability and security in a future with higher levels of VRE generation.

Resilience of the current fleet to changes in VRE/net demand

For fleet F1 (current fleet) in each region, we see little to no energy gaps emerge under the different cases. Gaps that do emerge are generally in cases where the system experiences sudden loss of PV in the middle of the day and the nature of the gap reflects the generating resources in the regions.

Victoria has a predominantly coal fleet but with significant hydro capacity able to provide operating reserve via the Murraylink interconnector (the only interconnection included in this model). Hydro capacity is highly flexible and its prevalence prevents energy gaps emerging in almost all cases modelled for the Victorian fleet. Only Case 5 and Case 6 show small gaps. The Victorian current fleet (F1) subjected to the loss of all rooftop PV over a 15-minute period on a moderate to high demand day (Case 5) is shown in Figure C.9 as an example.

Figure C.9: Victoria, F1, Case 5



Source: Endgame Economics

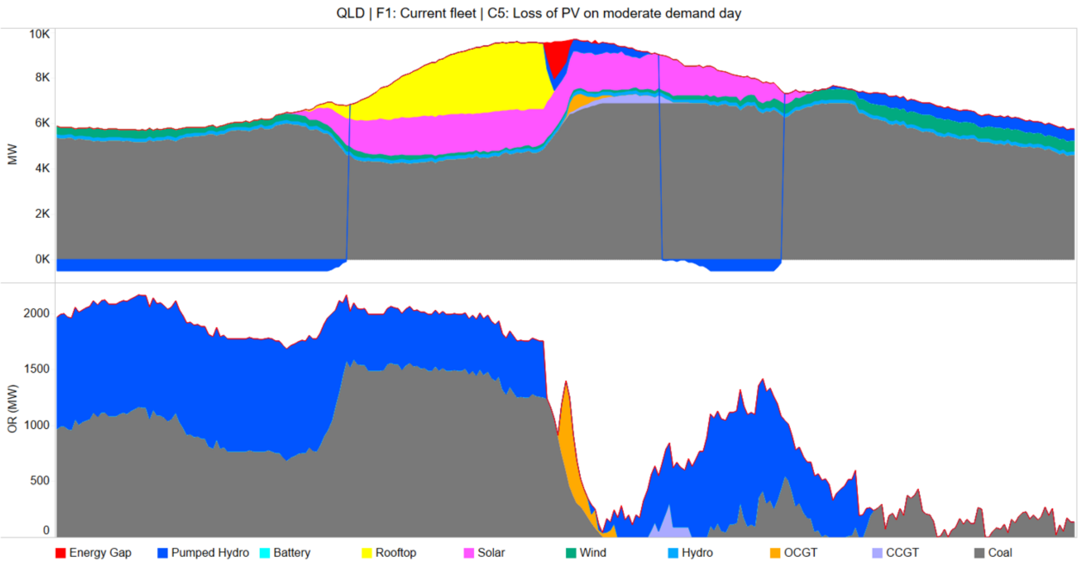
When faced with a sudden loss of PV in the middle of the day, the hydro fleet ramps up very quickly to re-balance supply and demand. The system only experiences a small imbalance, which is unlikely to be of concern. Case 5 is an extreme scenario for this fleet, with the loss of around 2 GW of PV generation over 15 minutes. This is far beyond any forecast errors expected now or into the future. Accordingly, this relatively small imbalance is not very concerning, particularly when one considers that this imbalance could be met readily in the real world by capacity from adjacent regions via interconnectors as well as other sources, such as demand response.

What is notable, however, is that significant baseload capacity is provided by the coal fleet, with flexibility provided by gas, hydro and interconnection (most of which is not modelled). If some of the coal capacity was not online, or if the hydro and other interconnection was significantly constrained, a larger gap may have emerged. As will be discussed later, the self-commitment of reserves by participants to manage risks is critical to the question of whether an operating reserve service is needed to avoid such gaps.

In Queensland, we see a significant coal fleet, as we did in Victoria, but also less flexible hydro capacity in reserve. This results in a larger energy gap when a sudden change in VRE is experienced.

The Queensland current fleet (F1) subjected to the loss of all rooftop PV over a 15-minute period on a moderate to high demand day (Case 5) is shown in Figure C.10. Note that in this case the scale of the loss of generation is higher (around 3 GW), due to the higher penetration of solar PV in Queensland.

Figure C.10: Queensland, F1, Case 5



Source: Endgame Economics

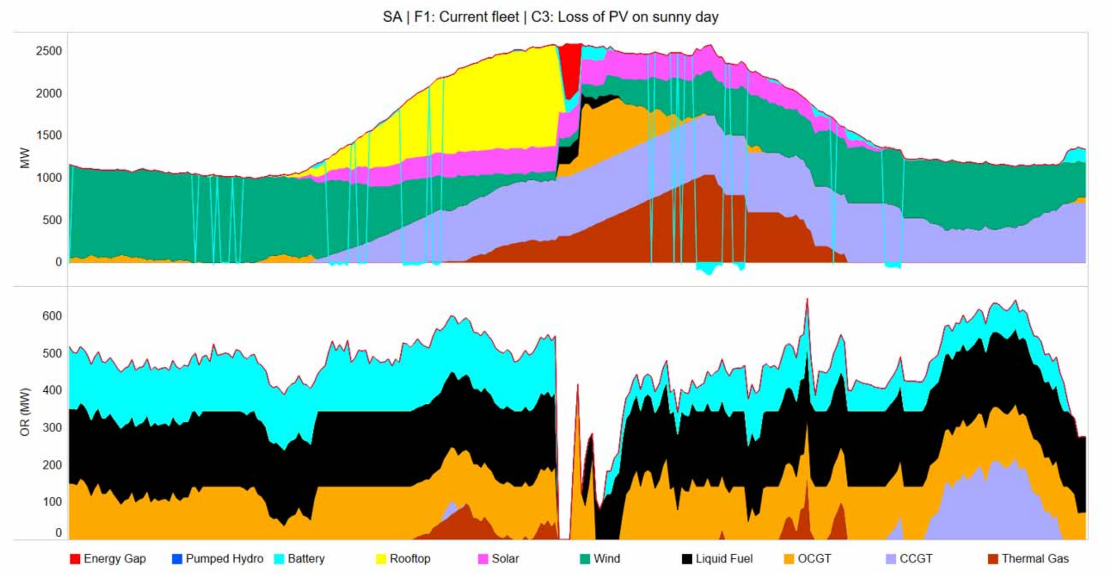
The energy gap in this circumstance is more directly related to a lack of flexible capacity in reserve. While there is significant coal capacity in reserve, it is only able to ramp relatively slowly when online to meet the sudden drop in PV. We note also that the model is based on ramp rates for coal generation from the ISP assumptions, which are higher than the capability of coal to ramp in the real world. OCGT is able to ramp quickly if online, but in this case has to start-up before it is able to contribute to the supply/demand balance. While the pumped hydro units at Wivenhoe are available, they are not sufficient to address the significant loss of generation in this case.

This case clearly shows that the Queensland fleet is less flexible than the Victorian fleet, particularly when taking into account that Queensland also has significantly less flexibility available to it across interconnection.

The current South Australian fleet has a much higher proportion of VRE, and therefore experiences higher VRE uncertainty. It has also evolved to account for the need for greater flexibility, with the retirement of coal and new entry of some battery assets.

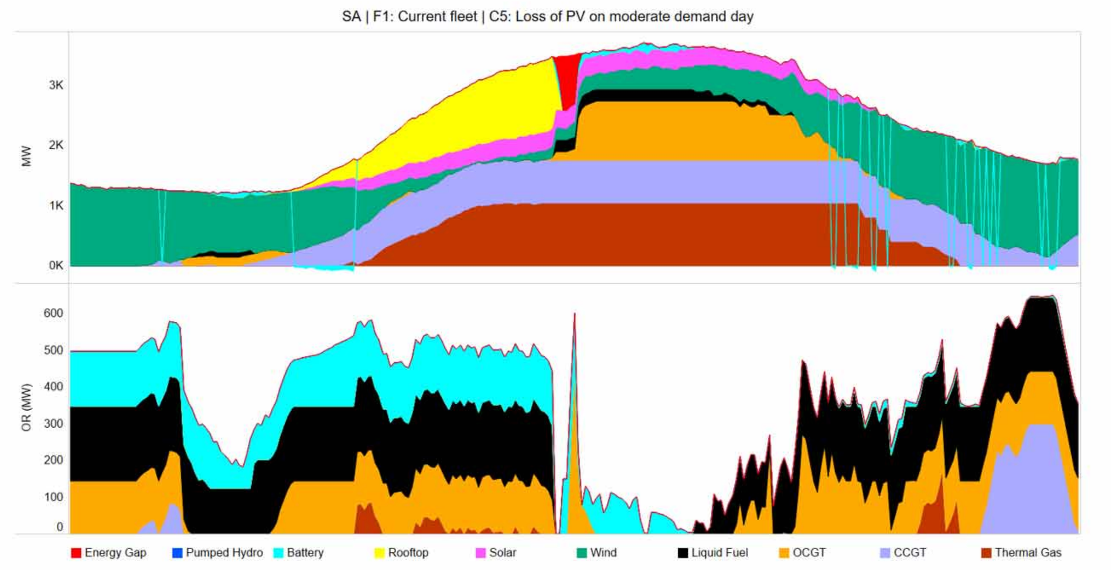
The South Australian current fleet (F1) subject to the loss of all rooftop PV over a 15-minute period on a sunny day (Case 3) and on a moderate to high demand day (Case 5) are shown in Figure C.11 and Figure C.12 respectively.

Figure C.11: South Australia, F1, Case 3



Source: Endgame Economics

Figure C.12: South Australia, F1, Case 5



Source: Endgame Economics

In these cases, we see energy gaps over multiple consecutive trading intervals. This appears to be caused by the severity of the event and the limited gas capacity online at the time of the event.

There is significant flexible capacity in reserve to respond in short timeframes. Battery capacity and curtailed utility-scale wind and solar provide a response immediately following the drop in PV, highlighting the flexibility of the current South Australian fleet in operational timeframes. However, sustaining this response appears to be a challenge. OCGT is required to start up and supply the remaining gap until other, slower-responding resources are available.

Resilience of the current fleet to *future* changes in VRE/net demand

In the above cases, we see small energy gaps emerge due to sudden changes in VRE on the current Victorian, Queensland and South Australian fleets. These energy gaps for current fleets are not particularly concerning for a range of reasons, principle among them are that:

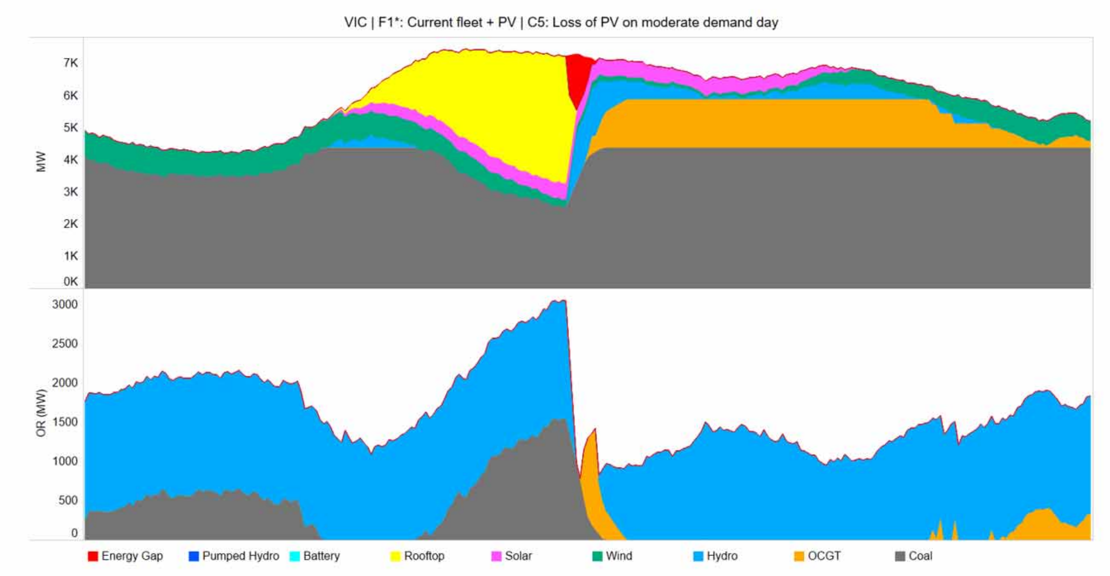
- these changes in VRE generation over very short timeframes far exceed the maximum VRE forecast errors that can be expected either now or far into the future (as discussed in policy paper 2)
- the model does not include interconnection, which has a very significant impact on outcomes in Victoria and a material impact in Queensland and South Australia
- the model does not include demand side response, and
- perhaps most importantly, the model does not include the self-commitment of reserves by participants (generators) in order to manage the risks they face in the energy market.

Naturally, as VRE penetration increases, the scale of changes in VRE also increases.

Fleet F1* was modelled as a sensitivity to specifically test the impacts that larger changes in VRE may have on the current fleet's ability to balance supply and demand. The hypothesis was that increasing VRE penetration would likely see coal generation de-commit during the middle of the day (rather than just operate at minimum generating limits), which would reduce the reserves available to the system.

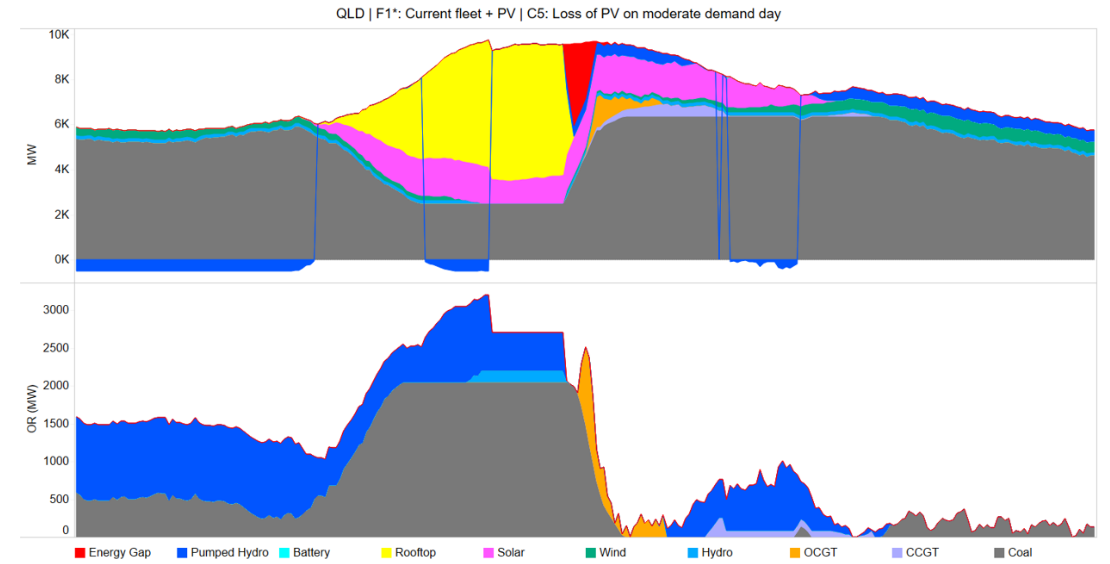
Fleet F1* adds significant rooftop capacity to the current fleet in each state. The Victorian and Queensland current fleets with additional rooftop PV capacity (F1*) subject to the loss of all rooftop PV over a 15-minute period on a moderate to high demand day (Case 5) are shown in Figure C.13 and Figure C.14 respectively by way of example.

Figure C.13: Victoria, F1*, Case 5



Source: Endgame Economics

Figure C.14: Queensland, F1*, Case 5



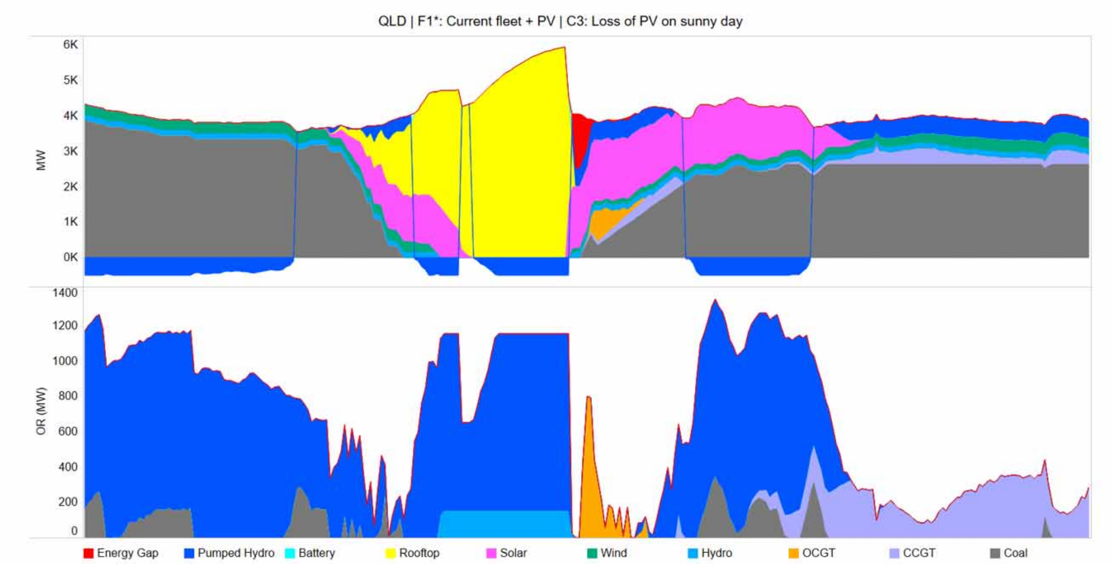
Source: Endgame Economics

Again, in Victoria we see hydro provide flexible capacity in short timeframes to address the imbalance. However, the remainder of the response needs to be supplied by coal, which takes longer to ramp up to fill the larger drop in VRE. OCGT takes time to start up before it is able to ramp quickly. The brown coal fleet (which is relatively inflexible and has high start-up costs) provides significant reserves during the middle of the day when it is running at minimum generating output. The provision of reserves is similar in this example to the earlier case based on the current fleet shown in Figure C.9, however the scale of the energy gap is more significant because the scale of the event it much more significant. Indeed, at around 5 GW of lost PV generation over a 15-minute period, it is well beyond anything that could be reasonably expected now or in the future.

In Queensland, we see similar impacts. While there is significant coal capacity in reserve, it takes longer to ramp up in the wake of the larger drop in VRE and a larger energy gap is experienced.

Impacts are exacerbated in both states when the coal fleet de-commits during the day. For example, Figure C.15 shows this for the Queensland current fleet with additional rooftop PV capacity (F1*) subject to the loss of all rooftop PV over a 15-minute period on a sunny day (Case 3).

Figure C.15: Queensland, F1*, Case 3



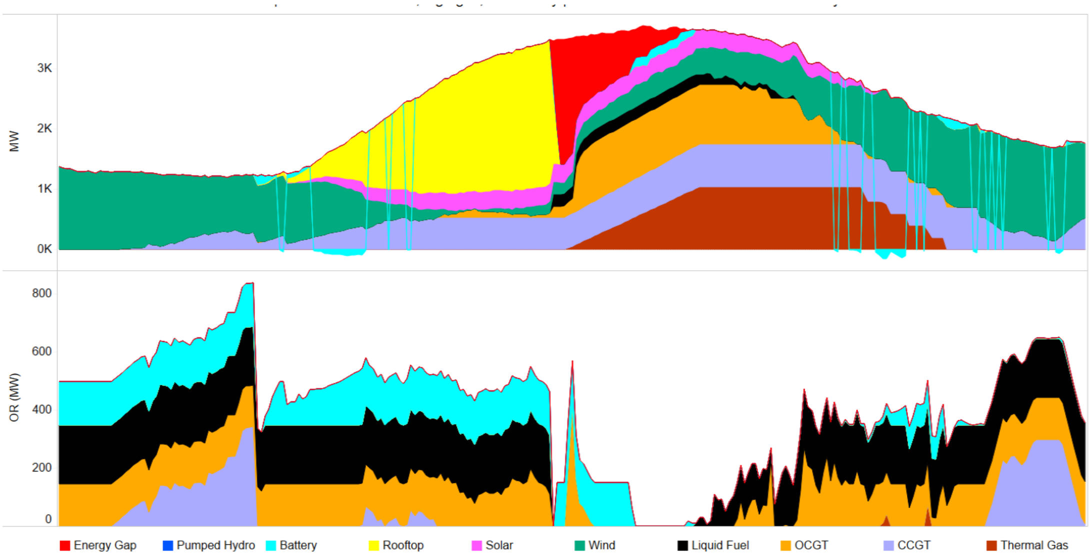
Source: Endgame Economics

The sheer volume of PV generation in the middle of the day causes the modelled coal fleet to de-commit to make way for rooftop PV to meet the entire generation requirements of the region. When the system experiences a larger drop in VRE, not only does the coal fleet ramp up slowly to address the imbalance, it also has to start up. The pumped hydro units at Wivenhoe and curtailed utility solar are available but are not sufficient to address the significant loss of generation.

Interestingly, the de-commitment of coal occurs in this case because the assumed behaviour of the coal fleet in the model is more flexible than we understand the actual performance of the coal fleet to be. For example, ramp rates are higher and start up costs are lower in the modelled world. In the real world we understand that the coal fleet (black or brown coal) is highly unlikely to de-commit for a period of time during a single day. It is more likely that some coal units may be de-committed seasonally (e.g. during shoulder periods) due to the efficiencies from operating the remaining generating units at higher capacity factors. While this pattern of operation may reduce the headroom available from those coal units, it was noted that this relative reduction in available reserves would likely be managed on a portfolio basis by the coal unit operators by ensuring sufficient reserves are readily available from other sources.

In South Australia a significant energy gap also evolves when subject to a drop in VRE under the fleet F1* sensitivity. However, the nature of the gap is different. The South Australian current fleet with additional rooftop PV capacity (F1*) subject to the loss of all rooftop PV over a 15-minute period on moderate to high demand day (Case 5) is shown in Figure C.16.

Figure C.16: South Australia, F1*, Case 5



Source: Endgame Economics

While there is some flexible capacity from batteries, OCGT and liquid fuels in reserve, it is not sufficient to quickly return the system to balance. The energy gap therefore persists over a longer duration while the relatively slow technologies of CCGT and thermal gas take time to turn on and ramp up.

Key learnings from modelling of the current fleet

Modelling of the current fleet highlights that regions heavily dependent on incumbent thermal generation are not well suited to operation in a future with higher levels of VRE generation, and consequent higher levels of net demand variability and uncertainty. Coal generation in particular is likely to struggle commercially due to its inflexibility, with periods of low prices during the middle of the day and difficulty taking advantage of price spikes caused by uncertainty. Slower responding gas generation (such as OCGT that takes some time to start up, and CCGT) may be better placed to manage the daily variability required of operation in a system with higher VRE generation, but may still struggle to respond to price spikes caused by increasing uncertainty.

The system will therefore need to evolve to ensure that there is sufficient flexibility to meet the supply/demand balance across all timeframes when subject to higher levels of variability and uncertainty.

In the future, we will see the retirement of coal as it nears the end of its technical life. Retirement could potentially occur before then if it is commercially untenable to operate in a future with higher VRE penetration and entry of new flexible plant. Some stakeholders have suggested that existing gas is unlikely to retire, but rather is more likely to change its way of operating. This could involve converting to liquid fuel sources and operating far less frequently (say, during critical peak generation needs or during VRE droughts).

As discussed in earlier sections of this paper, analysis of the investment pipeline for future flexible capacity and interconnection suggests that the fleet already appears to be evolving in such a way that more flexible capacity will likely be on the ground in the future to respond quickly to VRE ramps. The investment pipeline does not appear to show any appetite for investment in slower responding equipment, such as new gas plant that may take up to 30 minutes to turn on.

The following sections describe how the model provides insights into how potential future systems will be able to respond to changes in VRE. It explores both a flexible development pathway – which we consider to be the more likely path – and an inflexible pathway.

C.9.4 Key takeaways for the future power system

This section evaluates the results from the modelling exercise. The modelling covers the three regions of VIC, QLD and SA. Within each region six fleets are each exposed to six VRE uncertainty events, as explained in appendix C.5 and appendix C.6. A selection of the modelling results are shown to highlight the learnings from the exercise. The results are arranged by the timeframes over which reserves are needed. This is aligned with the order used above, being:

1. Flexibility in operational timeframes: five minutes to one hour
2. Availability over a day: 24 hours
3. Availability over multiple days: days/weeks

1. Flexibility in operational timeframes: five minutes to one hour

A key takeaway from the modelling exercise is that the ability of the generating fleet to respond quickly to uncertain events is:

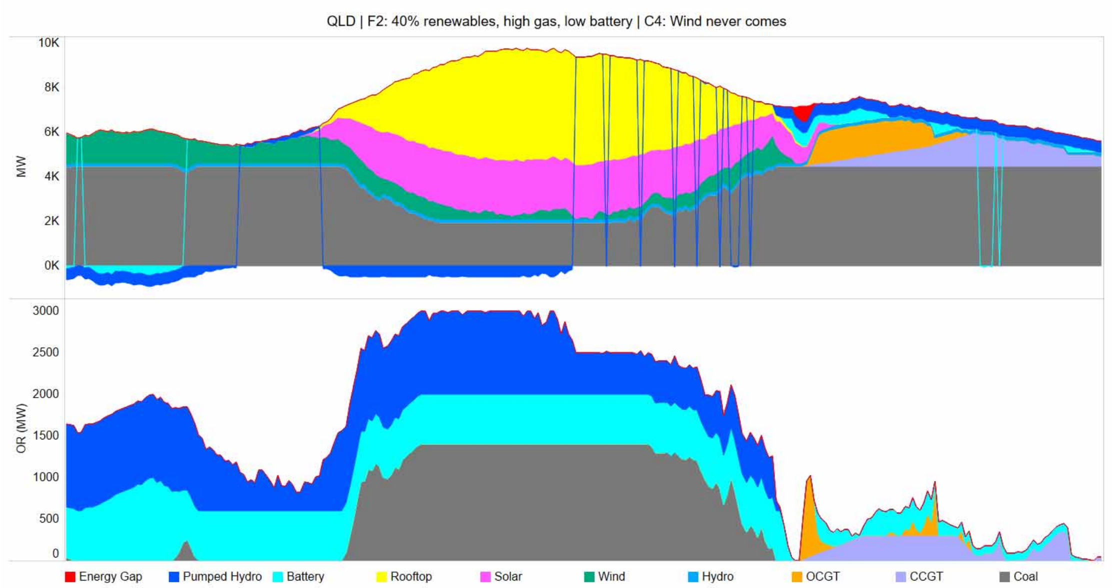
- **enhanced** if the region develops by firming renewables with highly **flexible** capacity, such as batteries and pumped hydro, that takes seconds/minutes to start up.
- **reduced** if the region develops by firming renewables with relatively **inflexible** capacity, such as slower responding gas, that takes close to 30 minutes to start-up before it can ramp.

For all regions, the more flexible fleets (high battery fleets) produced less severe energy gaps in operational timeframes than the comparable inflexible fleet (high gas fleets). Across all regions:

- The 40% renewable fleet with **high battery**, low gas performed **better** in operational timeframes than the comparable 40% renewable fleet with high gas, low battery.
- The 80% renewable fleet with **high battery,** low gas performed **better** in operational timeframes than the comparable 80% renewable fleet with high gas, low battery.

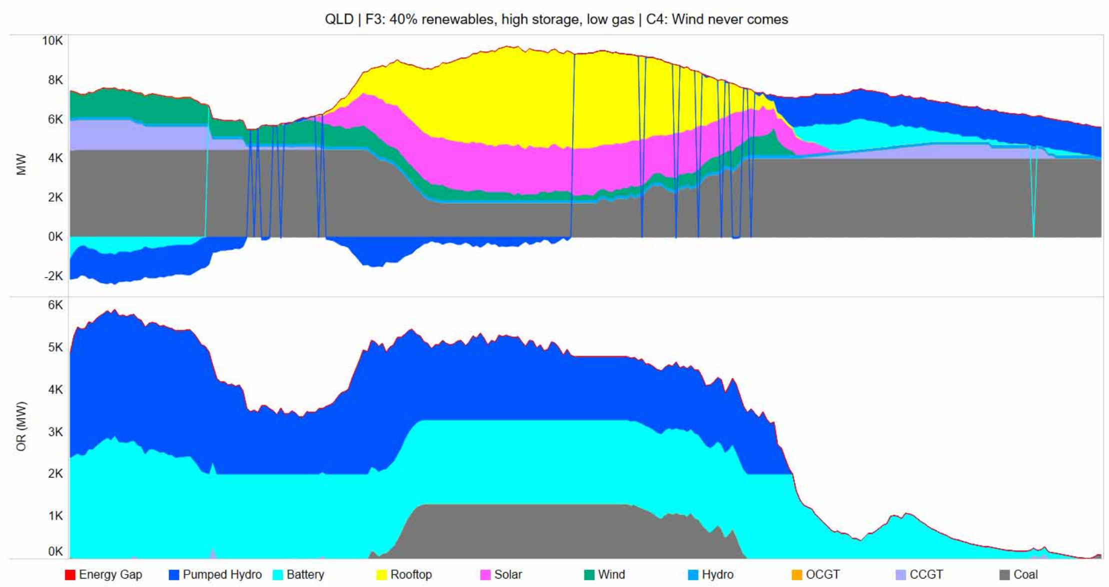
The series of Figures below compare a range of results for the flexible (high storage/batteries) fleets against the associated inflexible (high gas) fleets. For each comparison, all aspects of a scenario are held constant except for the flexibility of the fleet.

Figure C.17: Queensland, F2, Case 4



Source: Endgame Economics

Figure C.18: Queensland, F3, C4

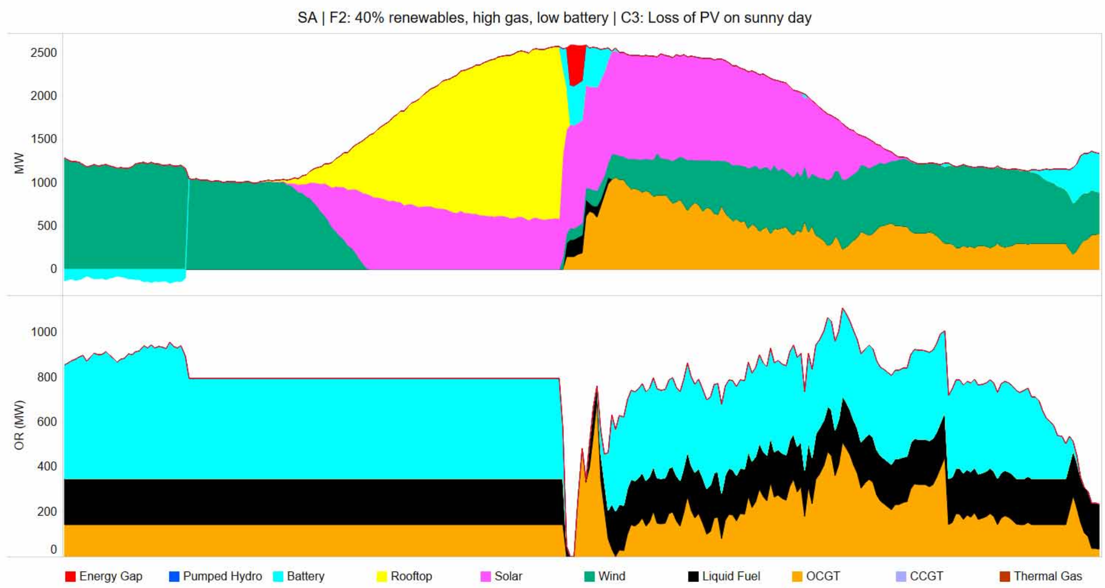


Source: Endgame Economics

Figure C.17 and Figure C.18 above, show the inflexible and flexible Queensland fleets at 40% renewables penetration (F2 and F3) exposed to the scenario where the wind was forecast to provide capacity during the evening peak, but instead it drops off (C4). In both scenarios the solar is tailing off because it is the end of the day so when the wind capacity does not come, the system has limited generation online and available to supply the evening peak.

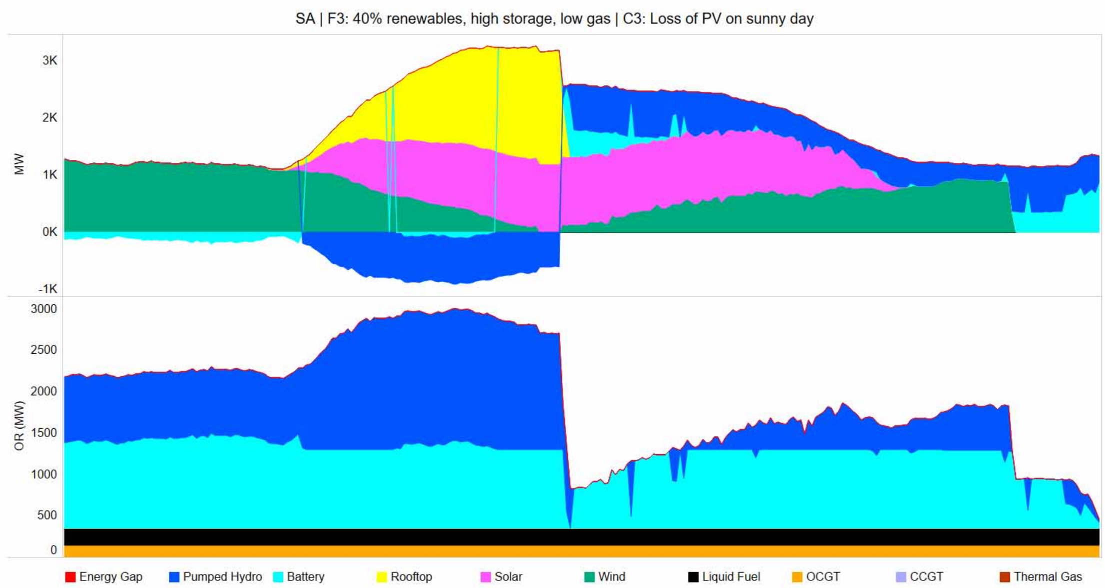
For the inflexible fleet, the existing coal and battery reserves are fully depleted. An energy gap emerges while the OCGTs ramp up. This is characteristic of a lack of flexibility. The flexible fleet, on the other hand, is able to meet the supply/demand balance throughout the event. With a high penetration of batteries and pumped hydro, the fleet has more than double the operating reserve capacity available to meet unexpected changes in net demand over a 30-minute time horizon. When the wind drops off, the system ramps up quickly to cover the shortage without an energy gap emerging.

Figure C.19: South Australia, F4, C3



Source: Endgame Economics
Note: the diagrams says F2 but it is actually F4.

Figure C.20: South Australia, F5, Case 3



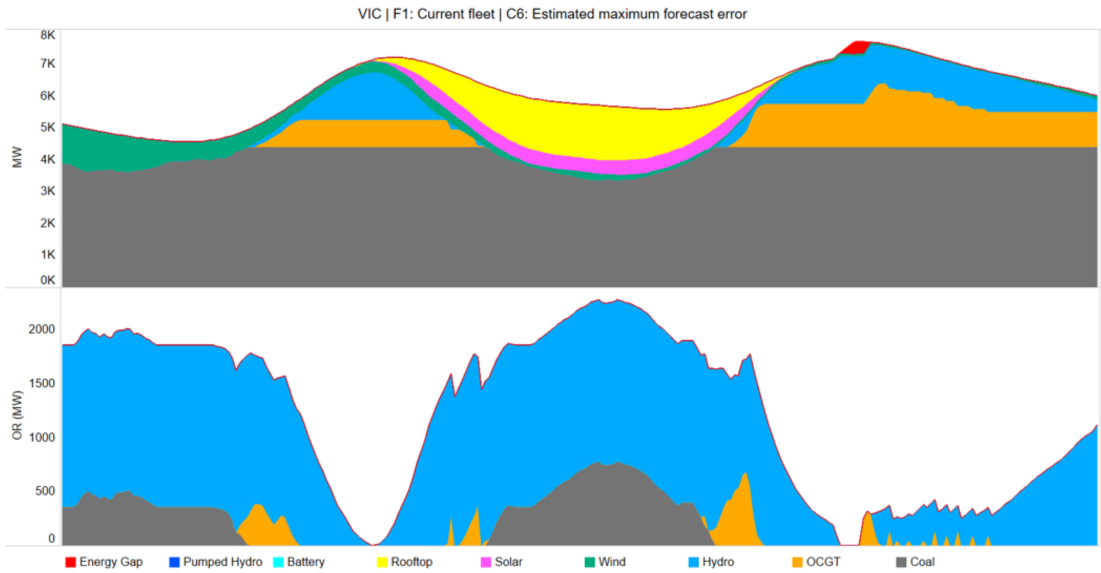
Source: Endgame Economics
Note: the diagrams says F2 but it is actually F4.

Figure C.19 and Figure C.20 above, show the inflexible and flexible South Australian fleets at 80% renewables penetration (F4 and F5) exposed to the scenario where the rooftop PV drops from full output to 0MW in 15 minutes (C3). In both scenarios there is curtailed solar (large scale) (pink) that is bought online as rooftop PV drops off (noting that this VRE is not included in the OR graph on the bottom).

For the inflexible fleet, the existing coal, liquid fuel and battery reserves are fully depleted. An energy gap emerges while the OCGTs ramp up. This is characteristic of a lack of flexibility. The flexible fleet is able to manage the event. With a high penetration of batteries and pumped hydro, the fleet has more than triple the instantaneous operating reserve capacity at the time of the event. When the rooftop PV drops off, the system ramps up quickly to cover the shortage without an energy gap emerging.

The positioning of the fleet is critical to the ability of the system to balance energy in operational timeframes. Figure C.21 shows an example of a time when no reserves are available to the system in operational timeframes, and the fleet is unable to respond.

Figure C.21: Victoria, F1, Case 6



Source: Endgame Economics

As shown above, there are cases where this modelling shows that an energy gap occurs when the fleet does not have sufficient reserves available to respond. We need to be careful with the modelled outcomes here as they tend to occur when all thermal and other capacity is online and an event occurs when there is no spare capacity at all, rather than occurring when the spare capacity is not sufficiently flexible in operational timeframes.

In these cases (largely C6, the maximum forecast error case) the scheduled or flexible fleet is already generating at the time the net demand forecast error occurs. In the model this error was unable to be achieved by reducing the output of renewables at this time, because no renewables were online. This highlights an interesting dynamic that can be observed, assuming a region has sufficient resource adequacy:

- times where forecast errors are likely to be highest are times when a reasonable proportion of renewables are generating, and
- in contrast with the examples modelled here, at these times there is likely to be some headroom and reserves available elsewhere, made up of undispatched scheduled generators and headroom over interconnectors.

The key question becomes whether and when the system may be in a position where it has limited reserves available (e.g. because batteries are not sufficiently charged or gas not pre-committed) at a time when larger forecast errors are possible. This is not a question that the modelling can answer. It is a function of other factors not included in the model (such as participant self-commitment of reserves and available headroom from other sources such as demand response and interconnection). These questions are explored further in box below.

BOX 11: SELF-MANAGING RISKS IN OPERATIONAL TIMEFRAMES

As discussed in earlier sections of this paper, participants self-commit reserves to manage the opportunities and risks they face in the energy market. They do so because the participant is either unhedged and has an opportunity to benefit from high prices, or the participant is hedged and must generate when the prices are high to avoid the financial penalty of paying those high prices as a market settlement or to a contractual counterparty.

Commercial players see risk as a combination of magnitude and probability. It is helpful to consider how these aspects of risk are likely to evolve into the future:

- The magnitude of these risks is significant. Failing to generate 100 MW of power over a half hour period while the market is at its price cap incurs a financial penalty of $750,000 (50MWh at MPC), either as a lost opportunity if unhedged or as cash out the door if hedged. We can assume for argument's sake that this magnitude of risk will stay fairly constant.
- The probability of risk is changing into the future. The self-commitment of reserves has been largely sufficient to date to provide reserves to manage uncertainties experienced in the past. This includes uncertainties driven by contingencies, which are sudden unexpected by market participants at that time (having a very low probability of occurring at any time). The nature of future uncertainties driven by forecast errors is likely to be different and driven by known factors, such as weather variability. This means significant information is available to help participants understand when the probability of net demand variations is higher and when it is lower.

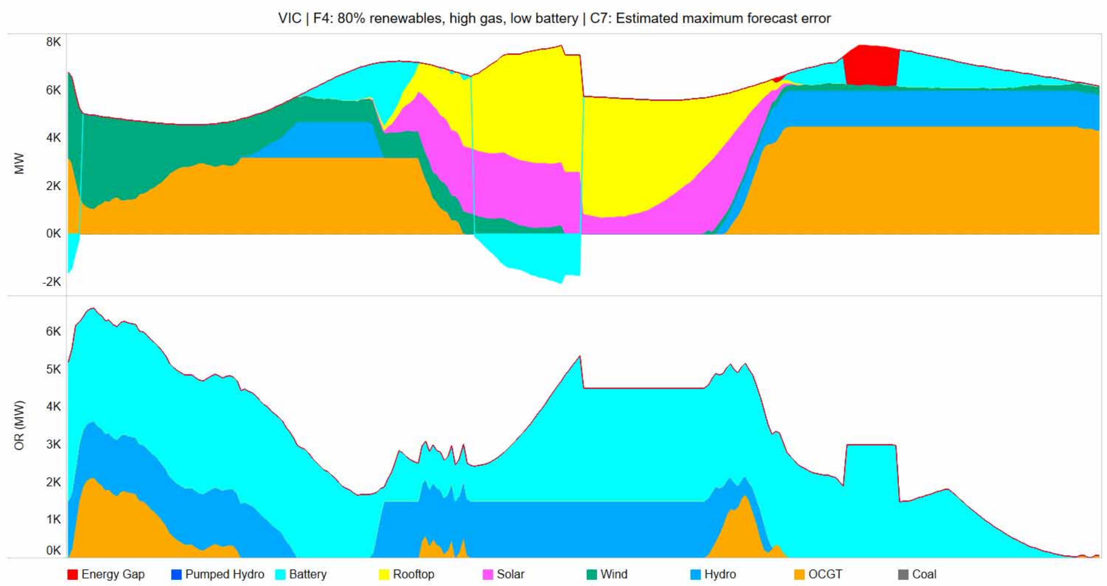
The above suggests that a working hypothesis could be that the ability of market participants to manage the uncertainties in net demand into the future through the self-commitment of reserves is likely to be enhanced, rather than hindered, by a shift toward those uncertainties being driven by known factors, such as weather. This would support the view that the current frameworks are likely to be capable of sending the appropriate signals for participants to manage their financial risks in the market, and thereby continue to manage reliability risks for consumers.

2. Availability over a day: 24 hours

Another key finding from the modelling is that if the system develops by firming renewables with capacity that is limited in duration (MWh), such as storage technologies, then energy gaps may arise if that capacity is not adequately pre-positioned to meet the needs of the system throughout the whole day. This issue does not tend to arise if the system develops with a heavy reliance on gas, because that technology is not limited in duration by its fuel source. The extent of this issue is heavily dependent on the behaviour of storage capacity.

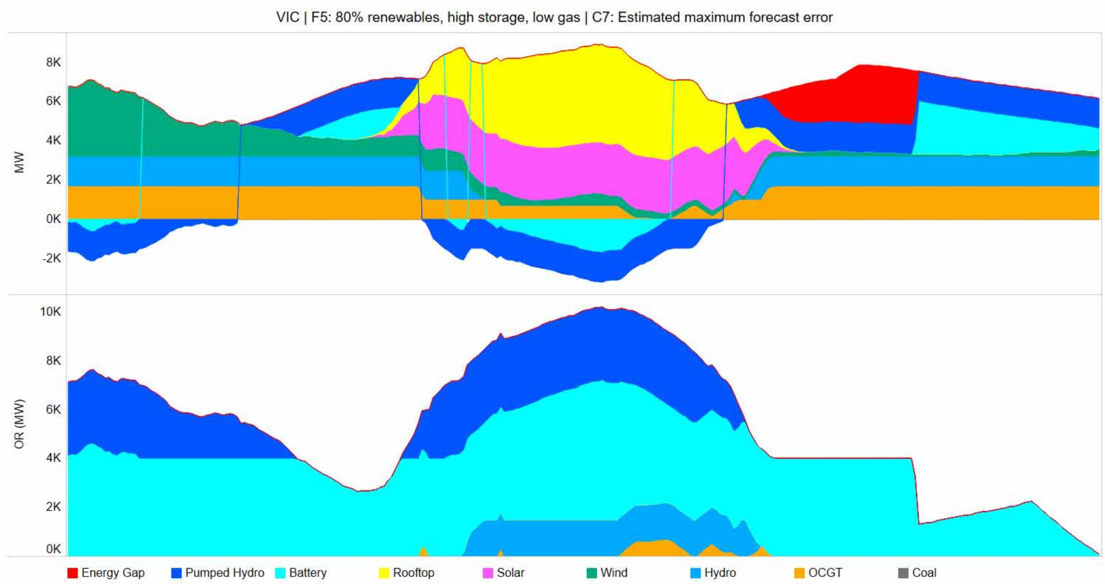
Figure C.22, Figure C.23 and Figure C.24 compare modelled outcomes over the same day in Victoria with 80% renewables (F4, F5, and F5), exposed to the maximum forecast error occurring at the end of the day (C6). The figures compare the response of the inflexible fleet (Figure C.22) against the response of the flexible fleet (Figure C.23), and also compares a further case where batteries are assumed not to have charged at the beginning of the day (Figure C.24).

Figure C.22: Victoria, F4, Case 6



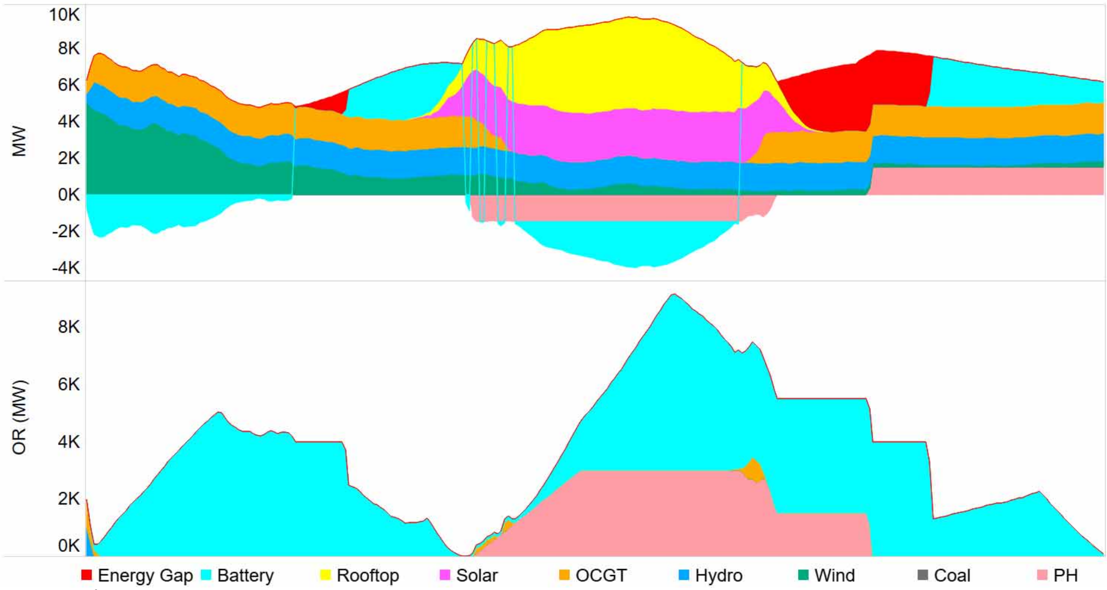
Source: Endgame Economics
Note: The label says C7 but that is the same as C6.

Figure C.23: Victoria, F5, Case 6



Source: Endgame Economics
Note: The label says C7 but that is the same as C6.

Figure C.24: Victoria, F5 (with 0MW of initial charge), Case 6



Source: Endgame Economics

Comparing these three Figures shows that when a fleet has more energy (MWh) available to it, it is better able to meet the bulk energy needs of the system over the course of a day. For the high gas fleet, the OCGT and hydro assets that were in reserve, are fully exhausted to cover the evening peak. When the forecast error event occurs and more energy is needed, the relatively small amount of battery capacity is left to meet this need. There is not enough energy stored in the batteries to cover the entire event, so an energy gap emerges. However, the OCGTs running at around 4,000MW for the entire evening, reduce the strain on the system and help limit the severity of the energy gap.

When this is compared to the high battery fleet in Figure C.23, it clear that the system with a limited duration of stored energy will be less capable of managing the event if it is not appropriately pre-positioned with sufficient stored energy. The OCGT and hydro assets are used to cover a portion of the evening demand but their lower MW capacity in this fleet means that the system still needs more energy to cover the evening peak and beyond. The system uses pumped hydro and batteries to provide the additional energy. However, this leaves the system vulnerable when the maximum forecast error event hits and that additional net demand continues for the rest of the day. With the pumped hydro and batteries already partially depleted, these units have insufficient energy to cover the event, leading to a large and extended energy gap. This shows that a system with a high penetration of energy storage and relatively lower levels of capacity that are not resource constrained, will need to maintain sufficient state of charge to manage potential longer duration events.

To show the importance of having enough stored energy for the high battery fleet, the event was repeated but the characteristics of the energy storage units where adjusted such that they had 0MW of stored energy at the beginning of the day. This is shown in Figure C.24. In this case, for the batteries and pumped hydro to be able to discharge they first need to charge. In this case they do charge to manage excess solar PV and to meet the energy needs expected later in the day. However, this fleet is not as well positioned as the fleet that started with 50% charge to address a long duration event that occurs later in the day.

As with the results relating to reserve needs in operational timeframes, these results should be interpreted in light of the limitations of the model. These limitations include that there is no interconnection, demand response, or participant self-commitment of reserves in this model. The lack of interconnection is particularly relevant to the cases explored above, noting that Victoria is highly interconnected with other regions. As also noted in relation to reserve needs in operational timeframes, the participant self-commitment of reserves here will be informed by the risks faced by participants in the market and how they manage those risks through commitment decisions, see Box 11.

3. Addressing a lack of capacity over multiple days: days/weeks

This modelling is not well suited to showing issues emerging on the power system over multiple days and weeks. This model runs over individual days, and the state of charge at the beginning of each day is assumed. Furthermore, we do not consider the issues raised by the rule change requests reach as far as to allow us to consider the risks of energy gaps due to renewable resource droughts. Regardless, the results still raise the question of whether there may be emerging risks of insufficient capacity to meet demand over the course of days to weeks in a future with a heavy reliance on renewables firmed principally by storage technologies.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APC	Administered price cap
APP	Administered price period
ARENA	Australian Renewable Energy Agency
ASEFS	Australian solar energy forecasting system
AWEFS	Australian wind energy forecasting system
CER	Consumer energy resources
CIS	Capacity investment scheme
Commission	See AEMC
DI	Dispatch interval
DUID	Dispatchable unit identifier
EAAP	Energy adequacy assessment projecti
EMMS	Electricity market management system
ESOO	Electricity statement of opportunities
FCAS	Frequency control ancillary services
FUM	Forecast uncertainty measure
GWH	Gigawatt hour
IRM	Interim reliability measure
ISP	Integrated system plan
LOR	Lack of reserves
MPC	Market price cap
MWH	Megawatt hour
MT PASA	Medium-term projected assessment of system adequacy
NEL	National electricity law
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NEO	National electricity objective
NER	National electricity rules
NERL	National energy retail law
NERO	National energy retail objective
NERR	National energy retail rules
NGL	National gas law
NGO	National gas objective
NGR	National gas rules

NSP	Network service provider
ORDC	Operating reserve demand curve
PASA	Projected assessment of system adequacy
PD PASA	Pre-dispatch projected assessment of system adequacy
Proponent	The proponent of the rule change request
RERT	Reliability and emergency reserve trader
REZ	Renewable energy zone
RIS	Renewable integration study
RRO	Retailer reliability obligation
RXS	Regional excess supply
ST PASA	Short-term projected assessment of system adequacy
TWH	Terawatt hours
TWG	Technical working group
UIFG	Unconstrained intermittent generation forecast
USE	Unserved energy
VCR	Value of customer reliability
VRE	Variable renewable energy