



COAG  
Energy Council

# ENERGY SECURITY BOARD

## Post 2025 Market Design Consultation Paper

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## LIST OF ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
C&I	commercial and industrial
CoAG	Council of Australian Governments
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DEIP	Distributed Energy Integration Program
DER	distributed energy resources
EAAP	Energy Adequacy Assessment Projection
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
ESB	Energy Security Board
ESS	Essential System Services
ESOO	Electricity Statement of Opportunities
EV	electric vehicle
FCAS	frequency control ancillary services
FFR	fast frequency response
GW	Gigawatt
IBR	inverter based resources
ISP	Integrated System Plan
MDI	Market Design Initiative
MLF	marginal loss factor
MPC	Market Price Cap
MT PASA	Medium Term Projected Assessment of System Adequacy
NEM	National Electricity Market
NEO	National Electricity Objective
NSP	Network Service Provider
PSSAS	Power System Security Ancillary Services
PV	Photovoltaic
RAMs	Resource Adequacy Mechanisms
RERT	Reliability and Emergency Reserve Trader
RIT-T	Regulatory Investment Test – Transmission
RoCoF	rate of change of frequency
RRO	Retailer Reliability Obligation
ST PASA	Short Term Projected Assessment of System Adequacy
TOU	Time of Use
TNSP	Transmission Network Service Provider
UCS	Unit Commitment for Security
VPP	Virtual Power Plant
VRE	variable renewable energy
WDRM	Wholesale demand response mechanism

## EXECUTIVE SUMMARY

### Why the market design needs to change

The energy system is changing. New technology and digitalisation are providing new choices and opportunities to customers. At the same time, the rapid uptake of Variable Renewable Energy (VRE) and Distributed Energy Resources (DER) is well underway and the existing ageing thermal generation fleet is progressively retiring. The National Electricity Market (NEM) of the future is very different to that of the past.

Similar changes are occurring in many electricity markets across the world. But the rapid pace of change occurring in Australia and the adoption of distributed (rooftop) solar photovoltaic (PV) systems is remarkable. At least 2.2 million households now have solar PV on their rooftops, up from 100,000 a decade ago. This means the changes to the NEM design are likely to be among the first in the world to meet these needs.

All the changes occurring mean that the current set of systems, tools, market arrangements and regulatory frameworks is no longer entirely fit for purpose and able to meet the changing needs of the system and customers. To address these matters, the Energy Security Board (ESB) is tasked by the former COAG Energy Council to develop a market design for the NEM that delivers secure and reliable power at least cost to consumers, and accommodates the changes underway and expected in the future. This paper sets out for consultation a number of potential solutions to identified problems and opportunities.

### Overview of workstreams within Post-2025 market design program

To deliver future market designs, the ESB set up seven workstreams to consider the issues and develop potential solutions. The initial work has been done by the market bodies (the Australian Energy Market Commission (AEMC), Australian Energy Market Operator (AEMO) and Australian Energy Regulator (AER) working together with ESB staff. Industry and consumer groups and other stakeholders have been involved and consulted along the way. The outputs from each of the individual workstreams have inter-relationships and need to be considered together for a coherent whole design.

The seven workstreams are:

- Resource adequacy mechanisms (RAMs).
- Ageing thermal generation strategy
- Essential system services.
- Scheduling and ahead mechanisms.
- Two sided markets.
- Valuing demand flexibility and integrating DER.
- Transmission access and the coordination of generation and transmission investment.

### Resource adequacy mechanisms (RAMs)

While the system requirements change over the next 10-15 years, the issue is whether existing mechanisms are sufficient to support the needs of the system, or whether other complementary measures are needed. In particular, are existing mechanisms sufficient to support the required new investments?



A complex mix of resources is required to deliver electricity at the lowest overall cost to customers. The mix includes energy from thermal and renewable sources, flexible supply and demand response resources, and energy storage of different types<sup>1</sup>.

Ensuring there is sufficient and timely investment in this mix of resources is critical to delivering a secure, reliable and affordable supply of electricity. If private sector balance sheets are to fund this significant new investment at least cost, then there will need to be a degree of confidence over future prices and the role of government in the market.

The ESB is considering various options for how investment signals could be improved. First are those mechanisms that would strengthen the current real-time price signals for investment that should then flow through to expectations about future sustained high prices. Second are those mechanisms that introduce a longer duration price signal for investment, either through a separate mechanism or through longer duration contracting.

- The ESB invites views on whether the current resource adequacy mechanisms in the NEM are sufficient to drive investment in the quantity and mix of resources required through the transition.
- The ESB is considering the merits of a spectrum of options intended to strengthen signals for investment and support the reliability and security needs of the system.
- Feedback is sought on how governments could best leverage the long term investment signals in the NEM to reflect their jurisdictional policy priorities.

### Ageing thermal generation strategy

With 61% of the existing thermal generation resources in the NEM likely to exit over the next two decades, it is essential for reliability of supply and affordability of electricity prices that this transition is efficient, and delivered at least cost to customers.

Uncertainty around the timing of exit of ageing thermal generators could have a significant impact on the affordability of electricity. This uncertainty could result in replacement capacity being delayed or new investments requiring a higher return on capital. This could lead to higher electricity prices. This uncertainty is also reflected in the level of transmission investment required under the Integrated System Plan (ISP).

Premature exit of ageing thermal generation can also increase the risk to security, reliability and affordability of electricity supply, as replacement capacity may not be available to ensure resource adequacy and electricity prices may be higher than necessary, allowing existing generation to attract additional rents.

There are a number of measures that would reduce the uncertainty around the timing of exit of ageing thermal generation and the risk of premature generation plant exit. These include measures to ensure that essential system services are available, the 42-month notice of closure rule, and Retail Reliability Obligations that may be triggered. The ESB will consider whether there are additional measures needed during the transition period as thermal generators retire.

- The priority of this workstream is to meet the needs of the transition at least cost to consumers.
- The ESB is seeking feedback on the likely effectiveness of current arrangements to minimise consumer costs and manage risks to reliability and security over the transition (including their materiality) and whether additional measures may be needed for the transition, taking into account other changes to the market design proposed through this work.

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<sup>1</sup> See AEMO 2020 Integrated System Plan <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp>



## Essential system services

As more renewables come into the system, providing lower cost energy, there is a need to update how other essential services are provided. These essential services keep the system in a secure and reliable operating state and become increasingly important as older thermal generators retire. Many of the attributes and capabilities provided intrinsically by the ageing thermal generation fleet are not intrinsic to inverter based renewable technologies and must be sourced and procured by other means.

This work to define the necessary capabilities and characteristics for new services, and to consider options about how best to procure these services, is vital for the system to be both secure and affordable. It will set foundations for the future NEM. Effective market signals are needed to achieve short term operational goals and support longer term investment decisions to deliver a secure system and drive down costs to consumers.

- A framework is set out to enable the market to progress to more sophisticated ways to deliver system services as the system changes, and as technology and market conditions allow.
- Feedback is sought on procurement mechanisms and market arrangements for a range of services including an operating reserve spot market, fast frequency response as a frequency control ancillary services (FCAS) style spot market (from assets like batteries), structured procurement for synchronous generation commitment (for system strength and inertia) potentially combined with an ahead mechanism, with support for further longer term consideration for an inertia spot market.

## Scheduling and ahead mechanisms

In 2025, the system will be more complex, and variable and changing patterns of demand and supply create challenges in keeping the system balanced. This can lead to costs for consumers (for example through AEMO directions) that could be avoided by better market design. Getting greater visibility of the resources available in the system supports the ability to achieve real time economic dispatch of the system and reduces reliance on operator intervention into the market to assure system security and reliability.

Changes to market arrangements are considered that introduce greater visibility and certainty of resources on the system ahead of real time. The proposed changes also provide greater opportunity for DER (including demand) to participate and support lower operating costs and investment requirements.

- A spectrum of options is set out. These are intended to introduce greater visibility and certainty of resources ahead of real time.
- Options for development include a voluntary ahead market to procure and/or trade relevant system services (with or without energy) with a financial commitment. Options to introduce a compulsory ahead market design are not intended to progress.

## Two sided markets

There is potential for customers, including owners of DER, to participate actively in future markets and unlock value from their flexibility. Making demand more flexible can support lower investment requirements and create operational efficiencies that benefit all consumers. Where they choose to do so, individual customers can partner with retailers or third party providers to exchange their load flexibility for cheaper overall supply and potentially contribute to system security services. These options are already emerging (e.g. load shaping offers using pool pumps and hot water systems). As transport systems and other elements of our economy electrify, two sided markets help ensure the system is capable of taking advantage of these changes for the net economic benefit of consumers.

Getting the market framework right is the key to accommodating different customer needs and ensuring appropriate consumer protections are provided for families and businesses.

- The intention of a progressive shift to a two sided market is to better reward the value provided to the system of flexible demand and supply.
- Reforms are focused on facilitating new types of participation in the market, enabling greater innovation and choice to customers, and on working out how to best incorporate price-responsive supply and demand into real time dispatch and forecasting processes.
- Engagement with consumer stakeholders is important to ensure two sided market arrangements are designed in a manner that is not overly complex and that maximises participation from a broad range of customers (in partnership with retailers and other service providers).
- Adjustments to the consumer protections framework will be needed to make sure consumers have fit-for-purpose protections that reflect new ways of engaging with energy services providers.

### Valuing demand flexibility and integrating DER

To ensure we maximise the value for all consumers of DER there is a need for technical, regulatory and market arrangements to support their effective integration. A lot of resources have already entered the system, but efforts to coordinate and effectively integrate these resources (to realise their potential value) must quickly catch up.

The value of these resources, and their potential flexibility, is increasing. Electricity market arrangements do not currently make it easy for new and different types of service providers to participate. Arrangements that facilitate innovative new business models and integrate new technologies in the system are needed in ways that are fair for all.

- The priority for the post-2025 program is to integrate DER into the market, including the range of design changes we canvass throughout this report.
- Reforms will seek to provide opportunities for DER to participate where possible and efficient – making it easier for DER to provide services into all markets, and for owners to get value for their investments.

### Transmission access and the coordination of generation and transmission investment

The shift to locate generation in different places is a challenge for the existing transmission network, connections to it, and how it is accessed and used. We need arrangements that can efficiently manage congestion on the grid and get renewable power to consumers by making sure investment can happen in the right places (e.g. signals to encourage new generation into REZs or to have big batteries located where the system needs them most). A combination of regulatory and market arrangements are needed to support efficient and timely investment to deliver efficient outcomes to customers and investors.

- The reforms for transmission access will include interim measures to address current congestion as well as frameworks to support efficient and timely investment over the longer term.
- Work is focused on how best to introduce progressive and proportionate reforms to transmission access, that deliver benefits to consumers and support an overall coherent market design.

### Developing a coherent package of reforms

One of the biggest value adds of the post-2025 reform program is the ability to map out a coherent long term reform path.

Ordinarily, incremental changes are considered on an individual basis, and this may not be the best way to consider a whole of market redesign. The value of considering a broader program of reform enables a systems thinking approach to be taken, so design elements can be optimised together. This also means it is important the evaluation process carefully considers how the different program elements work together, to limit the risk of unintended consequences as far as possible.

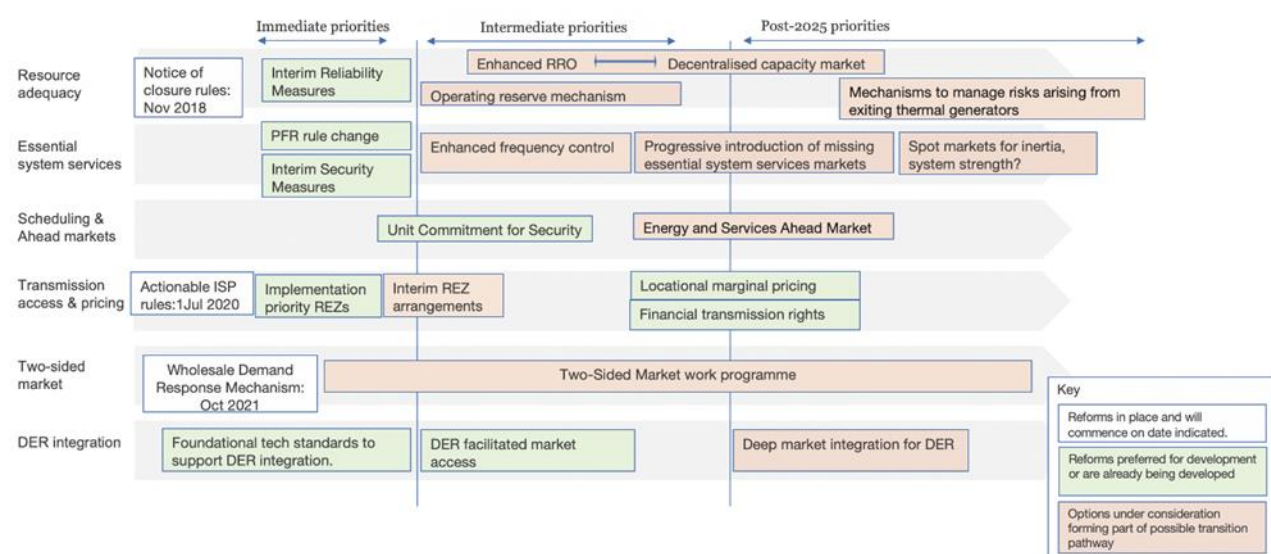
Once a package of reforms has been agreed, progressive implementation of the potential reforms will reduce the risk of unintended consequences. The high-level plan beyond 2025 sets out where more sophisticated tools, systems and arrangements may be needed to address the strategic challenges facing the NEM as these evolve over the next 10-15 years.

This work has already started with work to action the ISP, develop interim system security and reliability measures and introduce Renewable Energy Zones (REZs) now in place or underway. While some early and interim measures are being delivered to address needs already emerging within the system, a progressive approach for delivering initiatives enables the impacts of each set of measures to be felt before building further on these with additional reforms. This approach also enables a continued focus on delivering changes needed to support the transition at least cost to consumers.

A representative example showing at a high level how the post-2025 reforms could build on early measures taken is illustrated below. While the measures represented here are not a recommended option, depicting them over these horizons shows the potential to build on the changes made in each phase. This figure represents the measures highlighted in this paper and how a progressive implementation for reforms may proceed. By introducing a suite of measures progressively, there is scope to gain better insights about how each set of measures may, in combination, work to address the evolving challenges and unlock other opportunities. The risk of layering multiple solutions onto problems is reduced.

The congruency of reforms over the short and medium term through to longer term horizons needs to be evaluated. Reforms that are likely to be required and delivered over those periods can be considered together, enabling an assessment of how the combined changes impact consumers, the market and system. This approach also enables changes in future phases to build on other changes that have taken place already.

FIGURE 1 PHASED MARKET DEVELOPMENT – A REPRESENTATIVE EXAMPLE



The ESB notes that the market design option(s) developed via the Post-2025 program need to work with other reforms underway in the broader policy environment (for example rule changes lodged and already initiated by the AEMC). Where interdependencies exist, these relationships may have implications for changes to current systems, tools and processes. The market design option(s) should be coherent and viable packages that fit with the broader reform agenda, be proportionate to the scale of both the challenges and opportunities, and not impose unnecessary costs onto consumers and market participants (for example due to inefficient sequencing of activities).

Regular and ongoing collaboration across market bodies and the program workstreams is continuing to ensure initiatives remain aligned and to reduce duplication where possible.

### Next steps

The ESB welcomes feedback from stakeholders and all interested parties on the potential solutions set out in this consultation. The ESB will continue to work closely with market bodies and stakeholder work groups over the next 5-6 months to evaluate which mix of options should be taken forward as a future market design.

The next phase is to evaluate potential solutions. Option(s) for future market design will be developed over this period with input from stakeholders, with design options released for consultation around late December 2020 or early 2021.

The ESB will provide advice to Energy Ministers on changes to the existing market design, or recommend an alternative market design, to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least cost by mid-2021.

# 1. INTRODUCTION

## 1.1. Background

This paper presents an overview of the progress made by the Energy Security Board (ESB) on the Post-2025 market design project. We seek the views of stakeholders and interested parties on the issues raised, and Section 1.2 below sets out how to let us have your views.

There are substantial changes occurring in the National Electricity Market (NEM), and they mean the existing NEM design has to adapt and change. Potential solutions are considered for various problems and a framework for how these possible approaches may be assessed to reach a coherent fit-for-purpose market design is explained. A further consultation is planned for December 2020 or early in 2021.

In March 2019, the former COAG Energy Council ('the Energy Council') requested the ESB to advise on a long-term, fit-for-purpose market design for the NEM. The request recognised the challenges faced by the current NEM design (discussed briefly in Section 2) and that a new design should comply with the National Electricity Objective ('the NEO')<sup>2</sup>. The 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 –*

- a) price, quality, safety, reliability and security of supply of electricity; and*
- b) The reliability, safety and security of the national electricity system.*

Any market design option(s) should contribute to meeting the outcomes set out in the former COAG Energy Council's Strategic Energy Plan, including its central outcome – delivering more affordable energy and satisfied consumers. Finally, outcomes should be consistent with the objectives set out in the Finkel Review<sup>3</sup>, to support an orderly transition for the NEM.

The Energy Council met in March 2020 and considered an ESB recommendation from the ESB that the Post-2025 market design program be approached in three key phases of development and delivery:

1. Short term (12-18 month) deliverables – interim reforms to be implemented as soon as practicable.
2. Intermediate deliverables – relate to substantial reforms to be designed by December 2020 with implementation (at least in part) before 2025.
3. Longer term deliverables – relate to policy concerning investment programs, ageing thermal generator retirement, and further integration of Distributed Energy Resources (DER). Implementation of this phase is likely to be after 2025.

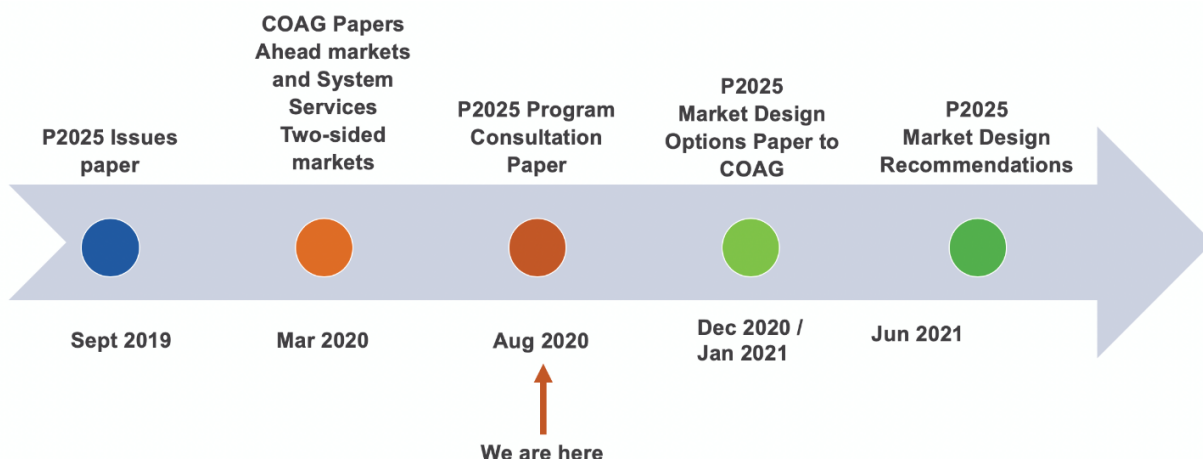
The Post-2025 market design project is seen as a pathway to a fit-for-purpose market design for the NEM. The transition happens over time through phases to ensure changes are fit for purpose. It is not envisaged that an entirely new design would be introduced at a single point in time. All reforms will be evaluated together to ensure they lead to an integrated solution, with final recommendations on all reforms made by mid-2021 and required legislation and rules then developed and introduced over time. The key deliverables program is shown in Figure 2 below.

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<sup>2</sup> <http://www.coagenergycouncil.gov.au/energy-security-board/post-2025>; the NEO is set out in section 7 of the National Electricity Law

<sup>3</sup> Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future; June 2017

FIGURE 2 POST-2025 PROGRAM KEY DELIVERABLES



At the Energy Council Meeting in March 2020, the ESB provided an update<sup>4</sup> that followed an earlier Issues Paper<sup>5</sup> and an international symposium held in November 2019<sup>6</sup>. This March update proposed workstreams and priorities in line with the staged approach. More detail about work groups and the proposed workstreams is available on the Post-2025 program website. The detail set out in this paper reflects the joint collaborative efforts of the ESB, Australian Energy Market Commission (AEMC), Australian Energy Market Operator (AEMO), and Australian Energy Regulator (AER).

## 1.2. Consultation and submissions

Stakeholders and interested parties are invited to make submissions on the issues raised in this consultation paper. There are specific questions at the end of each Market Design Initiative section (sections 4-10). More generally, the ESB invites comments on:

1. The potential solutions and how well the characteristics of these solutions address the challenges identified with the current market design. Where alternative solutions can be identified for discussion, these would also be welcome.
2. The proposed timing of the implementation of the changes to the market design and reasons for any alternative timing you may wish to propose.
3. Our proposed approach to classifying the broad range of consumer needs, and what may be alternative or complementary incentives or regulatory measures (including consumer protections) to consider in support of these needs.
4. The proposed approach and criteria to evaluate the range of potential solutions identified in each workstream and for assessing market design option(s) to be developed later this year.

If stakeholders would like to provide supporting analysis or discussion of your position in your submission, and in particular to illustrate your views on how particular solutions or characteristics of solutions meet the changing needs of consumers, participants, investors, and system or network operation, this would also be welcome. See Section 12 for details regarding timing and contact details for responses.

<sup>4</sup> [http://coagenergycouncil.gov.au/sites/prod.energycouncil/files/ESB%20Post2025%20Directions%20Paper\\_0.pdf](http://coagenergycouncil.gov.au/sites/prod.energycouncil/files/ESB%20Post2025%20Directions%20Paper_0.pdf)

<sup>5</sup> <http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-issues-paper-%E2%80%93-september-2019>

<sup>6</sup> Future Electricity Markets Summit



## 2. THE EXISTING NEM DESIGN AND ITS CHALLENGES

The existing NEM commenced in 1998. The design implemented market-based mechanisms in the competitive sectors and coordinated regulation of monopoly networks across the jurisdictions. The NEM brought together the electricity industries in Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.<sup>7</sup> It was designed to drive greater efficiencies and a better utilisation of resources, and has served the nation well until the last few years.

Initially the NEM design was characterised by:

- Relatively few, predominantly large thermal generating units with sufficient volume to meet intra-state demand.
- A mostly established transmission network designed to deliver generation to local demand with low levels of congestion outside of the regional interconnectors.
- Established distribution networks that were one directional, with very few distributed energy resources behind the meter in households or businesses.
- Consumers who were considered primarily as ‘consumers’ of electricity and, unless they were a large industrial load, had a limited relationship with their energy retailer or local network business.
- Increasing demand that supported increases in investment.

This market context and existing technology drove the key design choices for the NEM:

- Energy only spot market constrained by the market price cap (MPC), price floor, and cumulative price threshold (CPT).
- Open access for connection to networks.
- Regulation of networks.
- Interconnected regional spot and contract markets that match physical needs of the system to the need of participants to manage financial risk.
- Markets for a small number of ancillary services to keep the system in a secure operating state.

Now, however, technology and market conditions have changed substantially. The market needs to adapt, because:

- Technology is changing.
- Ageing thermal generators are progressively retiring.
- Governments, businesses and households are making choices that reduce emissions created by electricity generation.

See AEMO’s Integrated System Plan (ISP)<sup>8</sup> for more information on the changing NEM.

The Post-2025 market design project is considering how NEM market fundamentals need to be updated.

Sections 4-10 examine the problems faced by the NEM, opportunities for change and potential market reform options in detail. Broadly there are four challenges the redesign must address:

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<sup>7</sup> Western Australia and Northern Territory have separate electricity systems and market arrangements.

<sup>8</sup> <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp>



1. Meeting consumer needs – the diverse needs of all consumers, whose relationship with the market is changing and technology is offering opportunities to better meet these needs.
2. Managing variability and uncertainty – variability and uncertainty in power system flows that has accompanied the substantial increase in large and small scale variable renewables.
3. Need for capital replacement – as plants become commercially unviable and retire over the next 10-15 years and beyond, the replacement of the energy and essential services they provide is required.
4. Recognising demand flexibility and integrating DER – the value of demand response and load shaping must be recognised and DER needs to be effectively integrated into the system and the market.

These challenges reflect feedback received from stakeholders following the ESB's issues paper, published in September 2019, and broadly align with the strategic priorities set out in that issues paper.

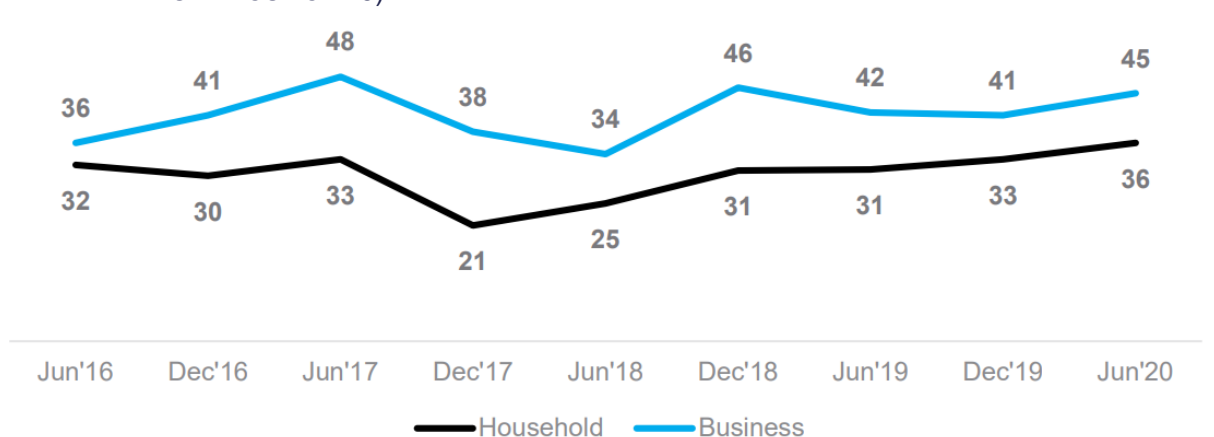
## 2.1. Meeting consumer needs

What consumers expect from the market and the way they interact with the market is changing. Market design needs to evolve to meet these changing expectations.

While affordability is not the only component of consumer need, it is critical. Any proposed market design change will need to demonstrably show value for money from a consumer perspective.

Over the last decade, consumers saw significant rises in the real cost of electricity. In June 2018, the Australian Competition and Consumer Commission (ACCC) reported that Australian domestic residential electricity retail prices had increased by 35% in real terms over the 10 years to 2017-18.<sup>9</sup> Energy bills are a significant challenge for many consumers, and contribute to the sentiment that consumer expectations are not being met across the sector; feedback to Energy Consumers Australia (ECA) is illustrated in Figure 3 below.<sup>10</sup>

FIGURE 3 ECA ENERGY CONSUMER SENTIMENT SURVEY – 'HOW CONFIDENT ARE YOU THAT THE OVERALL MARKET IS WORKING IN YOUR LONG-TERM INTERESTS' (% SCORING 7 OR HIGHER OUT OF 10)



<sup>9</sup> PwC, Future of Energy – Australian Energy Outlook Report, December 2019

<sup>10</sup> Via its use of regular Energy Consumer Sentiment surveys, the ECA has illustrated concerns across both household and business consumer groups in respect of the availability of easily understood information to make decisions regarding energy products and services, reliability of electricity supply, value for money of products and services provided by electricity companies (<https://energyconsumersaustralia.com.au/publications/energy-consumer-sentiment-survey-findings-june-2020-covid-special-reports>)

Although electricity costs and affordability will continue to concern consumers beyond 2025, expectations of improved outcomes are likely to be much broader. The rapid uptake of DER by both business and households is changing how consumers relate to the market and is providing opportunities to consumers and to the broader network. The ability to use DER on fair terms is now a key expectation of consumers. This presents numerous market design, regulatory and technical challenges to work through in ensuring these resources are integrated effectively and outcomes for all consumers, including those who own DER and those that do not, are fair.

Broader trends in digitisation and smart appliances and meters are all providing opportunities. We are now seeing virtual power plants (VPPs), aggregators, peer-to-peer trading, and the potential for new business models where energy is delivered as a bundled product via delivery of adjacent products and services (e.g. via purchase or leasing of electric vehicles (EVs), or flat quarterly fees for electricity usage via leasing of smart appliances).

Digitisation, and the platforms and services it enables, offers the potential to reward consumers who are able to offer services into the electricity market. In a digitised system, market design must meet the expectation of those who can offer services while delivering overall system benefits that ultimately improve outcomes for all.

Market design needs to recognise that not all consumers are the same. While meeting the unique needs of particular market segments will continue to be the primary domain of retailers, the segmentation of consumers has implications for market design. The market needs to recognise consumers will seek different services and products, have different needs and risk tolerances, and have competing demands outside the electricity market. Their responses to any market signals will be weighed against these demands, or they may not have the ability or motivation to respond at all.

The complexity of the market, in terms of the consumer's experience with engaging with it, also needs to be recognised by market design. Complexity can be a significant barrier to consumers being able to take up the benefits of new service offerings and can lead to poorer outcomes, particularly for consumers in vulnerable circumstances. The ECA has begun a comprehensive program of work to understand the needs of different residential and small business consumers.<sup>11</sup>

As energy is an essential service, it is key that appropriate protections for energy consumers remain in place over both the transition and beyond, particularly where new service providers and models may emerge to incorporate new technologies and other developments. While new service models will likely emerge at the retail level, the supporting regulatory and market frameworks need to ensure that efficiencies gained via wholesale market reforms also make their way to end use consumers through lower retail prices. Consideration will need to be given to consumer protection frameworks that apply to residential and small business consumers as these frameworks evolve.

Like residential consumers, large commercial and industrial (C&I) consumers also have diverse needs. Some C&I consumers may not see actively engaging with the electricity market as a commercial priority – others will see the NEM as an opportunity to generate (significant) revenue as well as an input cost. C&I consumers already bear a large proportion of system costs<sup>12</sup>, and the future market design needs to examine the allocation of these and how costs are passed on. Those C&I consumers who can be flexible should see appropriate incentives to do so. Similarly, C&I consumers that place a higher value on reliability than others should have the opportunity to purchase this higher service level.

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<sup>11</sup> Information regarding the ECA work on Consumer Archetypes is available on the Post-2025 program website.

<sup>12</sup> In 2019, RERT and FCAS costs totalled \$34.5 million and \$223 million, respectively. For residential consumers, retailers typically smear their proportion of costs across the customer base, and for C&I consumers these are usually directly passed on. AEMO, RERT Report for 2018-19, AER State of the Energy Market, p48.

Delivering customer outcomes requires coordination of many different aspects of electricity arrangements. As the supply arrangements change significantly, greater focus on this coordination and making the best, most flexible use of all elements required for delivering secure and reliable electricity will be required to ensure consumers are receiving efficient outcomes overall.

## 2.2. Managing variability and uncertainty

The increasing proportion of energy produced by variable renewable energy (VRE) or inverter based resources (IBR) has the potential to drive down both emissions and supply costs. Market and regulatory arrangements must be updated to ensure the increased variability, uncertainty and complexity associated with increasing VRE and IBR is managed.

Over the past decade, the proportion of VRE on the system has increased significantly, with 17GW already installed in the NEM and VRE forecast to get to 27GW by 2025. With underlying demand on the NEM ranging from 16-35GW, these resources represent a significant proportion of the future resource mix.

FIGURE 4 PENETRATION OF VARIABLE RENEWABLE ENERGY RESOURCES IS INCREASING



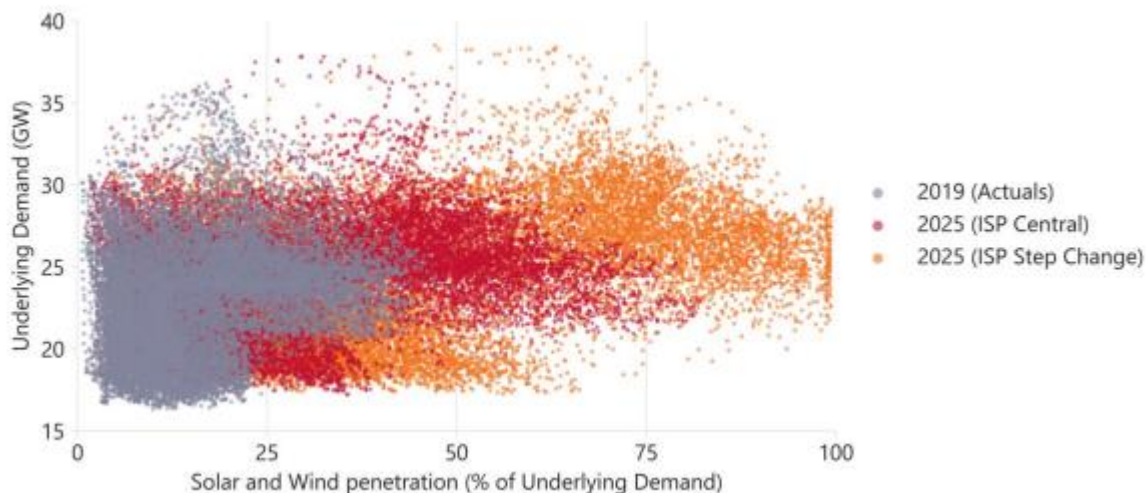
Source: ESB, Ahead Market presentation to Technical Working Group, June 2020

Given Australia's natural abundance of renewable resources, and the low running costs and falling technology costs associated with VRE generation, this forecast growth highlights the strong potential of Australia to be a world leader in transitioning our power systems to operating on low emissions variable resources.

Going forward, VRE is may be supported through a portfolio of energy storage systems of various depth of charge for intra-day, seasonal and longer-term support, with an increased role for gas-powered generation as coal-fired generation exits.

Resources with variable output contribute to uncertainty in forecasting, which can lead to challenges in managing the system. Figure 5 shows the projected instantaneous penetration of wind and solar expected to be experienced in the NEM within five years. In small volumes, variable output can be managed easily, but as volumes reach levels we are now seeing in the NEM and in the future, rising variability (and extremes) in load and supply profiles affects system operation.

FIGURE 5 INSTANTANEOUS PENETRATION OF WIND AND SOLAR GENERATION, ACTUAL IN 2019 AND FORECAST FOR 2025 UNDER ISP CENTRAL AND STEP CHANGE GENERATION BUILD SCENARIOS



Source: AEMO 2020, Renewable Integration Study Stage 1 report, p6

This is challenging AEMO in its role as the system operator. There is increased complexity in scheduling, given multiple combinations of resources (including many that are micro-climate dependent) and an increase in real-time data feeds. Addressing this will require more sophisticated tools to forecast and manage the increase in uncertainty, and at the same time provide sufficient ‘warning’ to act – the co-optimisation challenge.

Previously, the range of resources that delivered energy intrinsically also delivered a range of characteristics that supported system needs via delivery of energy, frequency services and reserves. With the shift from a small number of large resources on the system to a large number of small resources, the potential combinations of service providers to deliver the range of energy and system services capabilities necessary to support the grid is now becoming a much more complex calculation in real time. The impact is exacerbated by the displacement of synchronous generating resources.

Actions often must be taken by AEMO to ensure there are sufficient resources available to meet reliability and security system needs in real time. The ESB’s Health of the NEM report and AEMO’s Renewable Integration Study explore the actual and possible deleterious security outcomes in further detail.<sup>13</sup>

To effectively address the issues associated with forecast variability and uncertainty in the system, current market design needs to evolve to meet some of the challenges identified above.

#### Need for capital replacement

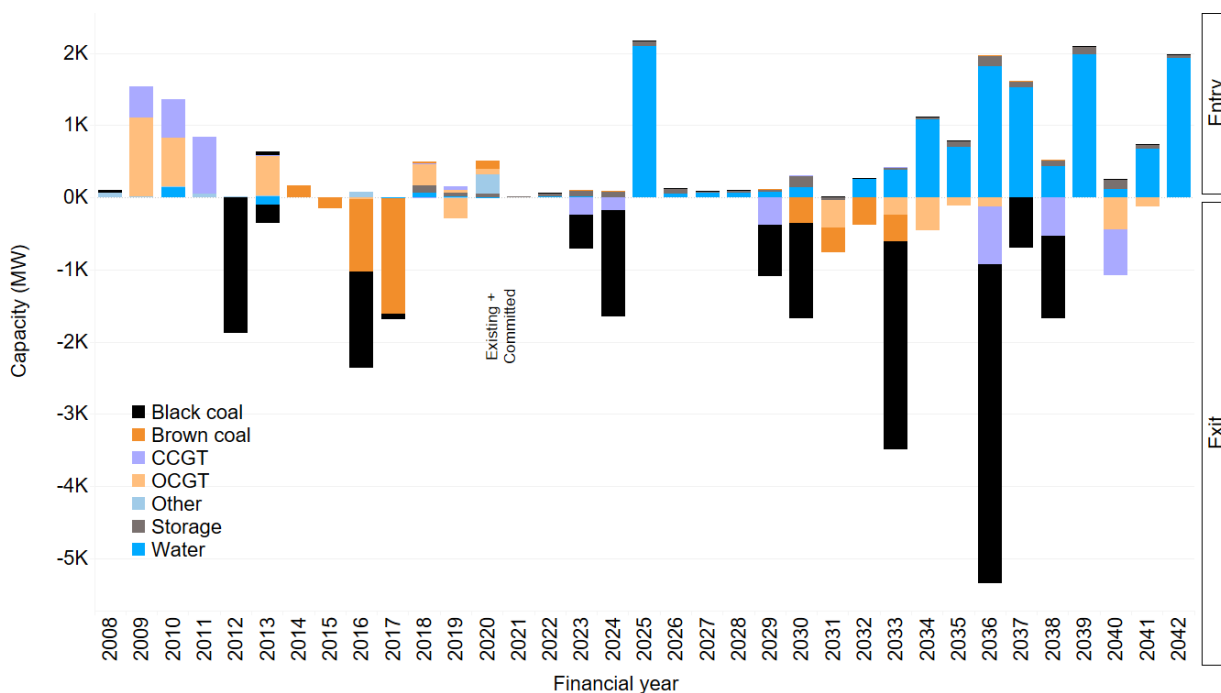
While plant exit has been anticipated for some time, the combination of many large exits over the coming 15 years or so – and their replacement by a mix of more distributed VRE, DER and new dispatchable and firming resources – means a significant reshaping of the NEM over this transition period (see Figure 6). The exit of generation is not in itself a problem. The challenge now is that the block nature of the tranches of capacity departing the grid may create gaps in dispatchable capacity (and erode available reserves), and departure of the essential services that are currently required to support the system.

<sup>13</sup> <https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris> and [http://www.coagenergycouncil.gov.au/publications/health-national-electricity-market-0#:~:text=The%20Energy%20Security%20Board%20\(ESB,and%20where%20improvement%20is%20required](http://www.coagenergycouncil.gov.au/publications/health-national-electricity-market-0#:~:text=The%20Energy%20Security%20Board%20(ESB,and%20where%20improvement%20is%20required)

These challenges are particularly significant where large scale thermal exit is unplanned or unexpected. The uncertainty around timing of plant exit coupled with the risk of unexpected or unplanned exit may lead to investment uncertainty for both new generation investors, as well as uncertainty for AEMO as integrated system planner. It may also create risks of significant market and price volatility as investment lead times for new generation or essential system services can be significant.

The exit of generation is not in itself a problem. The challenge now is that the block nature of the tranches of capacity departing the grid may create gaps in dispatchable capacity (and erode available reserves), and departure of the essential services that are currently required to support the system.

FIGURE 6 THERMAL SYNCHRONOUS GENERATION EXITING THE NEM



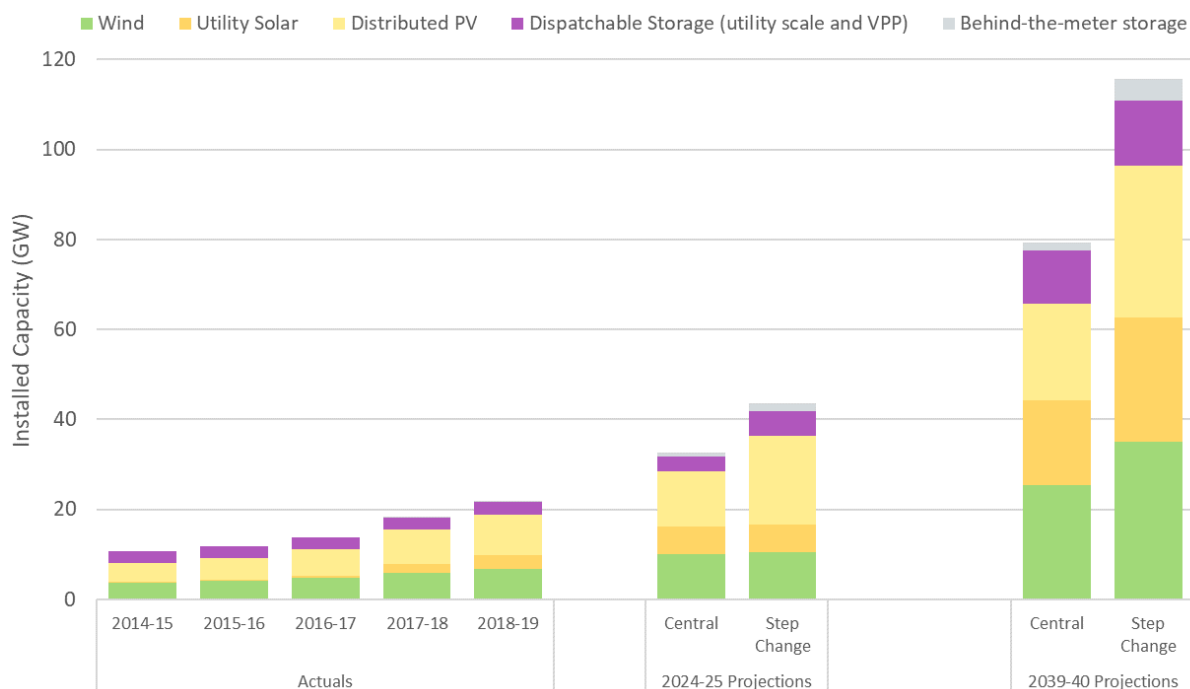
Source: AEMO and AEMC material, Ahead Market presentation to Technical Working Group, June 2020

In addition, the new investment is not on a like for like basis (see Figure 7). As the energy system trends towards increasing levels of VRE and DER, new forms of flexible capacity will be needed to replace exiting baseload generation. This new flexible capacity could be in the form of flexible generation (pumped hydro, gas-fired generation) and batteries as well as demand side response and DER. It will be critical to ensure that the market design provides adequate and enduring price signals to bring on these new forms of investment in a timely and cost efficient way.

To maintain a secure and reliable system with a high proportion of VRE and DER (and declining proportion of thermal generation assets), a range of essential system services needs to be defined and provided.

Some market participants and investors are noting the current market is not 'investable' for the types of dispatchable resources that can provide these services. While it is true that significant volumes of VRE or DER capacity are coming online, concerns have been raised that in the current economic environment, it can be difficult to make a business case to invest in dispatchable plant. The externality risks, technology and demand risks are seen as too high and the time in which revenue can be earned is uncertain. Clarity around the types of essential services needed to support the system, and how these will be procured, will help support investment decisions factoring in a range of potential forward revenue streams.

**FIGURE 7** INSTALLED WIND AND SOLAR CAPACITY IN THE NEM FOR 2019, WITH 2025 AND 2040 FORECASTS FROM FINAL 2020 ISP CENTRAL AND STEP CHANGE GENERATION BUILD SCENARIOS



Notes: Dispatchable storage includes all types of dispatchable storage regardless of depth (including VPP). Behind-the-meter storage includes all distributed storages that are not dispatchable.

It is imperative that we understand how current resource adequacy mechanisms (RAMs) may be able to adjust and if they are sufficient to address this transition issue. Alternative mechanisms may be required to sustain investment in existing plant and ensure they are replaced by a portfolio of technologies offering the full range of market services.

The exit of generation is not in itself a problem. The challenge now is that the block nature of the tranches of capacity departing the grid may create gaps in dispatchable capacity (and erode available reserves), and departure of the essential services that are currently required to support the system.

These challenges are particularly significant where large scale thermal exit is unplanned or unexpected. The uncertainty around timing of plant exit coupled with the risk of unexpected or unplanned exit may lead to investment uncertainty for both new generation investors, as well as uncertainty for AEMO as integrated system planner. It may also create risks of significant market and price volatility as investment lead times for new generation or essential system services can be significant.

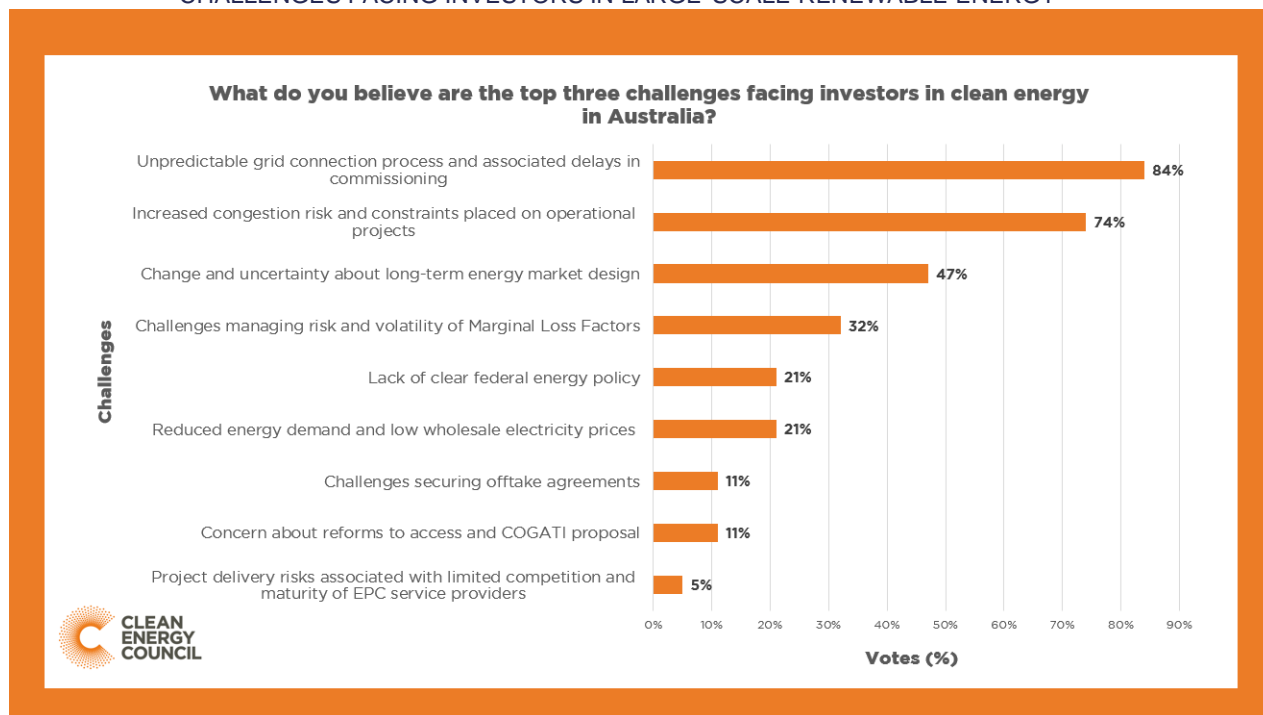
The market design needs to change to ensure there are enduring price signals that can drive investment in all the services needed for a reliable and secure supply to strengthen signals for investment, as well as a real-time price that better reflects the cost of providing all services needed for resource adequacy in operational timeframes. We also need to consider what additional assurances or backstops might be needed to support reliability and security if the market does not deliver within operating standards.

Supply arrangements are shifting away from large generators located in a centrally planned transmission grid to a future with large numbers of smaller generators diversely located throughout the transmission and distribution networks. While the regional market pricing approach suited the previous supply arrangements, the changing generation size and location requires these to be reconsidered to ensure consumers receive prices which better reflect the

value of altering generation and consumption. It is also important to consider increasing the location signals for generation investment to ensure optimal investment and use of transmission.

A recent poll taken by the Clean Energy Council highlights the diversity of risks that investors perceive as relevant to investment decisions (see Figure 8).

**FIGURE 8** POLL OF LEADING DEBT AND EQUITY INVESTORS IN AUSTRALIA REGARDING THE CHALLENGES FACING INVESTORS IN LARGE-SCALE RENEWABLE ENERGY



Source: Clean Energy Council

### 2.3. Need to value demand flexibility and integrate DER

The rapid adoption of all forms of DER upends the logic of the original market design, which must be changed to accommodate the increasing DER uptake. At least 2.2 million households in the NEM have solar PV on their rooftops, up from 100,000 a decade ago. Other DER are now emerging at economic levels, and the uptake of batteries in particular is expected to follow a similar rapid path. Bloomberg New Energy Finance forecast that Australia's power system is on track to become the most decentralised in the world.<sup>14</sup>

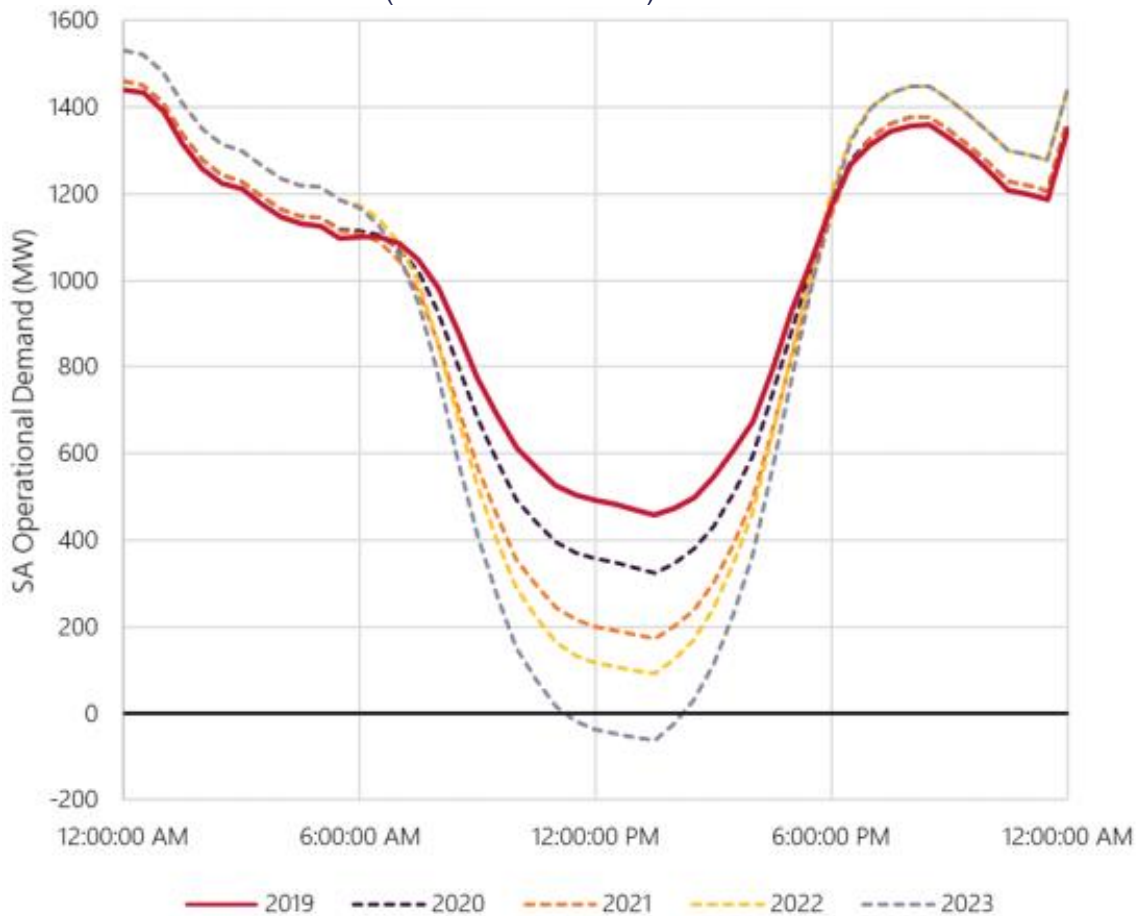
The current approach to integrating DER, apart from some major business consumers, has largely relied on fixed feed-in tariffs which compound the problem of fixed price load-following hedges for consumption, which allow consumers to use or generate as little electricity as they like, when they like, for the same reward/cost. Creating market transparency and more cost-reflective price signals will go a long way to helping both incentivise investments (without subsidies) and facilitate greater adoption of DER and physical system control.

These structures are contributing to a significant hollowing out in demand during the day, and increasing evening demand ramps (see Figure 9 for an example in South Australia last summer). These effects can lead to system security issues for AEMO as minimum system demand falls.

<sup>14</sup> Bloomberg New Energy Finance New Energy Outlook 2019, Executive Summary, p4



FIGURE 9 EFFECT ON SOUTH AUSTRALIAN OPERATIONAL DEMAND FROM INCREASING DISTRIBUTED PV GENERATION (10 NOVEMBER 2019)



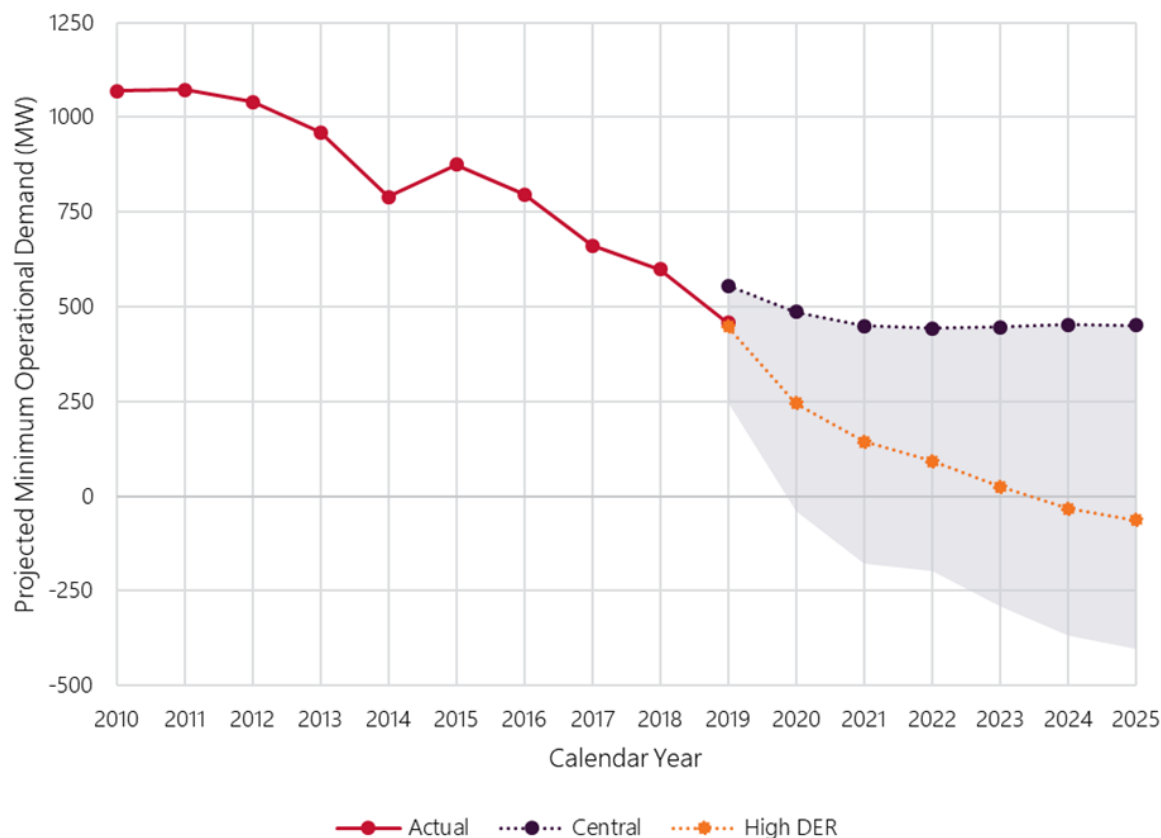
Source: AEMO, Minimum Operational Demands Thresholds in South Australia, May 2020, p18

Synchronous generators that currently provide many of the services required to keep the system secure need a minimum level of demand to operate. The 2020 Electricity Statement of Opportunities (ESOO) projects minimum operational demand to decline rapidly in all regions<sup>15</sup>.

Figure 10 shows the range of possible minimum demands for South Australia, shaded in grey.

<sup>15</sup> [https://aemo.com.au/-/media/files/electricity/nem/planning\\_and\\_forecasting/nem\\_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2](https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2)

FIGURE 10 MINIMUM OPERATIONAL DEMAND PROJECTIONS FOR SOUTH AUSTRALIA



Source: AEMO, Minimum Operational Demands Thresholds in South Australia, May 2020 p19

Overall, existing tariff arrangements do not provide sufficient incentives for retailers to offer products that can provide opportunities for consumers to maximise the benefits of investing in DER; for example, by storing electricity generated by solar PV during the day, for subsequent use in peak times when electricity is more expensive.

The existing pricing arrangements also risk driving additional inefficient investment in the poles and wires networks which are paid for by all consumers.

These effects could be avoided with more cost reflective pricing that would also help consumers maximise the benefits from their DER and flatten load profiles throughout the day.

New market arrangements are already emerging in some states, particularly those with higher solar PV and DER uptake like South Australia. The rapid uptake in South Australia has seen the emergence of time of use (TOU) tariffs for consumers, to encourage the shift of non-essential demand to periods of the day where solar PV output is highest (running pool pumps, washing machines, and dishwashers outside peaks are examples).

TOU tariffs like this can also assist with the increasing challenge of managing the evening peak period (which coincides with a reduction in solar and wind generation output), thereby reducing system costs to all consumers.

Whilst these changes are positive, there is a rapidly emerging need and economic opportunity for DER to support the creation of a more efficient shape of the local demand requirements that will directly moderate wholesale prices, reduce system risk, and – through appropriate market design – directly benefit DER owners and the entire system.

These efforts continue to be important as the degree of scheduling complexity increases. Increased collaboration is required at the interfaces of local and wholesale systems, to ensure the system operator can balance resources at the wholesale level, and distribution networks can

coordinate and optimise the use of local resources and flexibility on their networks. Approaching this from the perspective of how the integrated system works together, with the potential to unlock benefits for consumers, communities, and the broader system, has implications for how timely and efficient investments are incentivised and regulated at both the transmission and distribution network level.

Effective integration of DER does not just reflect the frameworks and standards for connection and operation. *Effective* integration of DER (and demand) will facilitate a shift to a more active demand side, with a broader range of parties engaging in the delivery of 'energy' related products and services.

Most markets have both an active demand and supply side. In energy the supply side was historically designed to be the more active side of the market because technology was not at a stage to allow for an active demand side. Supplies have flexed up and down in response to demand, with capped wholesale prices to remove the risk of consumers being exposed to price points that are reached in the extreme, say as a short term financial consequences of a supply outage.

This dynamic is now less dominant with technology advances, and allowing for flexibility of demand side resources becomes possible and cheaper than wholesale generation at times.

The objective is that the system becomes more resilient, productive (cost effective), and flexible – benefitting all consumers. Changes emerging in states with a high uptake of DER, by both households and business, are an indicator of what changes are likely to be across the NEM, and illustrate why effective and timely DER integration is necessary.

### 3. MARKET DESIGN INITIATIVES

In response to the four challenges noted in Section 2, the ESB set up seven work programs – market design initiatives (MDIs) – to evaluate and develop market design options that tackle the challenges and capture the opportunities (see Table 1.)

TABLE 1 POST-2025 MARKET DESIGN INITIATIVES

Market Design Initiatives	
MDI-A	Resource Adequacy Mechanisms (RAMs)
MDI-B	Ageing Thermal Generation Strategy
MDI-C	Essential System Services
MDI-D	Scheduling and Ahead Mechanisms
MDI-E	Two-Sided Markets
MDI-F	Valuing Demand Flexibility and DER Integration
MDI-G	Transmission Access and the Coordination of Generation and Transmission

Each design initiative addresses a range of issues across the four strategic challenges:

- Meeting consumer needs – addressed by all MDIs, but especially by the MDI concerning the development of a two-sided market, which changes how consumers can manage their power bills.
- Managing variability and uncertainty – particularly relevant to the MDIs focused on essential system services and scheduling and ahead mechanisms. These initiatives ensure the system operator and market participants have the tools needed to keep the system in a secure operating state.
- Need for capital replacement – addressed in particular by the MDIs on resource adequacy, ageing thermal generation and transmission access. Collectively these initiatives examine how the market can help integrate new sources of generation and storage.
- Valuing demand flexibility and the integration of DER – a strategic challenge that cuts across and impacts all MDIs.

Sections 4 to 10 examine the details of the problems each MDI is addressing, and the design options the ESB has considered and those we propose to develop in more detail for further evaluation.

#### 3.1. Development of market design initiatives

Some MDIs are more progressed than others, and some parts of a design have been more considered. The transmission access and coordination of generation and transmission investment MDI is a good example, because the AEMC has progressed work on this matter for some time. It is also the case that some parts of a MDI are likely to be progressed and implemented earlier than 2025. Elements of the scheduling and ahead mechanisms and essential systems services workstreams are both initiatives in this category.

Because of the differing implementation timing and rates of progress, there is clearly a need for coordination by the ESB across the seven workstreams. One objective of the consultation is to work towards a similar degree of information across all workstreams in the Post-2025 program. This will enable comparison of potential solutions across each MDI workstream, and provide context about how each workstream can contribute to addressing the four strategic challenges

identified for the NEM. Where further detailed information is currently available to support assessment of solutions at workstream level, and/or will shortly be available in upcoming consultations, this is noted.

### 3.2. Transition period

The Post-2025 program covers the range of deliverables set out in Section 1.1 over the short, intermediate and longer term. In terms of the design measures covered in each of the timeframes, the work is as follows:

- Short term (12-18 month) deliverables – relating to Renewable Energy Zones (REZs), interim reliability and security measures are measures to address urgent issues in the market design ahead of the 2025 project recommendations.
- Intermediate deliverables – relating to development of Essential System Services, Scheduling and Ahead Mechanisms, Two-Sided Markets and Transmission Access Reform through the coordination of generation and transmission investment. Development of these matters for a recommendation at the framework level by the end 2020 is envisaged, with implementation for some aspects likely ahead of 2025.
- Longer term deliverables – relating to investment programs, an ageing thermal generation strategy and initiatives relating to development of DER markets, with implementation after 2025.

A number of variables will continue to evolve over this period, and throughout the transition it is imperative to continue to meet the changing needs of consumers as well as to maintain secure, reliable and affordable supplies of electricity. These changing variables include characteristics such as<sup>16</sup>:

1. Increasing penetration of DER in the system, including batteries at both transmission and distribution level.
2. Increasing penetration of VRE and IBR.
3. Changing and increasingly uncertain demand patterns.
4. Changing weather patterns, with more extreme conditions.
5. Reduction in minimum demand levels, correlating with increased distributed solar PV penetration.
6. Increasing locational distribution of supply and demand resources.
7. Reduction of thermal generation resources, with exits in significant blocks.
8. Increasing need for provision of essential system services as thermal plant exits.
9. Increasing complexity in real time, as combinations of resources are co-optimised in dispatch algorithms.

The set of systems, tools and arrangements to support the effective and secure operation of the NEM over the transition period will need to evolve in relation to the impacts of these changing variables. Once the reform package has been agreed a staged and progressive implementation will enable the evolving risks to be considered, ensuring arrangements and protections are fit for

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<sup>16</sup> These characteristics and their impact on the NEM are highlighted in AEMO analysis in AEMO Renewable Integration Study: <https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris>, AEMO 2020 ISP: <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp>, and AEMO ESOO: [https://aemo.com.au/-/media/files/electricity/nem/planning\\_and\\_forecasting/nem\\_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2](https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2)

purpose for each stage. Early measures introduced can be learnt from and built upon to support future reforms.

### 3.3. Relationship to other initiatives

A range of projects and initiatives are being pursued by the AEMC, AEMO, the AER and other agencies and organisations that seek to address some of the challenges we identify in this paper. This has been an area of considerable attention within the program, and the ESB has welcomed feedback received from across stakeholder groups to highlight where issues of potential congruency or interdependencies may exist.

As projects or rule changes will continue to emerge, a focus of the Post-2025 program is to ensure the design and development process delivers viable and coherent market design option(s). Where rule changes are already being considered, these are mentioned where they are relevant to the workstreams. Regular and ongoing collaboration across market bodies and the program workstreams is continuing to ensure initiatives remain aligned, and to reduce duplication where possible.

## 4. RESOURCE ADEQUACY MECHANISMS – MARKET DESIGN INITIATIVE A

### Key points

Maintaining security and reliability as the system transitions over the next 10-15 years while delivering lowest cost to consumers is critical. This section considers whether the current NEM design will bring forth timely and efficient investment to achieve this.

Some stakeholders have commented that the current environment presents risks that deter investment.

Current signals for investment are underpinned by expectations of future prices at levels required to justify new investment. However, questions have been raised regarding governments' willingness to tolerate periods of scarcity pricing that drive investment. In addition, the ESB has heard from stakeholders that forward price curves necessary to support investment may not be sustainable into the future because renewables and rooftop solar are reducing energy prices during the day. Consequently, price unbundling may be necessary to reveal the value of firming and a sufficient price duration to make it investible.

These concerns, coupled with the absence of long term price signals and the inability to hedge large demand risk, may deter future necessary investment, which in turn risks further intervention – a vicious cycle where consumers will pay more than necessary for investment. As a result of this, the ESB is also considering:

- A range of mechanisms to make the real-time price as efficient as possible to strengthen the current signals for investment. The ESB is proposing to consider the effectiveness of an operating reserve to better reflect real-time prices of reliability and leverage efficient investment.
- Options to create a price for reliability or capacity that may be separate and additional to investment signals for future expectations about the energy price. Specifically, the ESB is proposing to further consider whether an enhanced RRO or decentralised capacity market can work alongside real-time price signals to support resource adequacy.

We seek feedback from stakeholders on the effectiveness of the current investment signal, and measures proposed to strengthen it, or to overcome risks that deter investment, or both. We also seek feedback on how governments can best leverage long term investment signals in the NEM to reflect their jurisdictional policy priorities.

### 4.1. What is the problem this initiative is addressing?

This initiative considers whether the current NEM design will deliver adequate resources through the transition, at lowest cost to consumers.

The ESB is inviting views on whether signals for investment in new and existing capacity in firming or dispatchable plant are sufficient to maintain resource adequacy over the planning timeframe, and if the real-time market will work to make sufficient resources available when needed.

Based on feedback from some stakeholders that the current design presents difficulties for investing in dispatchable generation, this section considers a range of options to stimulate such investment. Maintaining a strong investment environment will promote competition in generation and help keep prices as low as possible for consumers, particularly as ageing thermal plants retire.



Investment may need a longer-term price signal, and this is currently delivered through financial markets. We consider mechanisms to make the real-time price as efficient as possible to strengthen the current signals for investment.

The NEM is designed to use forecast and actual high prices arising from scarcity in particular periods as a signal for new investment. In addition to these energy market incentives, much of the recent investment in generating resources in the NEM has been supported by government support for renewables. It is likely true that historical investment has also benefited from some form of support outside the market.

While average pool prices are expected to be lower in future, prices in some periods would need to be higher to incentivise investment in flexible generation and storage. However, given the risks noted in this section, sustained prices at the level required for dispatchable plant may be so high that government intervention is demanded.<sup>17</sup> This is driven by a concern that governments may not be willing to tolerate periods of high pricing that drive investment, and will instead intervene in the market. This perception, coupled with an absence of long duration price signals in the NEM and the inability to hedge large demand risk, may deter future necessary investment, which in turn risks further intervention – a vicious cycle.

As a result of this possible dynamic, the ESB is also considering options to create a price for reliability or capacity that is separate and additional to investment signals for future expectations about the energy price. Such a change would give policy makers greater direct control over the signal for investment and greater assurances that future investment will be forthcoming.

Finally, given the intense operational variability we expect to see in the NEM through and after the transition, backstops, while they should remain only as emergency responses, need to be ready to respond to sudden changes or unexpected situations. Given this, the ESB will also consider whether Reliability and Emergency Reserve Trader (RERT) processes and the recently introduced interim reliability reserve are as efficient as possible.

The ESB will review this range of options and, following stakeholder feedback and further investigation, will evaluate market designs that involve none, all or a combination of supplements to the current investment framework to ensure the NEM has adequate resources at the lowest cost to consumers.

### Current resource adequacy framework in the NEM

The existing framework for resource adequacy is underpinned by spot and contract markets and shaped by the reliability standard and price settings.

The NEM relies on the risk of very high prices during times of scarcity (scarcity pricing) to drive future investment. It does not have a separate price signal for capacity or reliability, as do some markets in other jurisdictions.

More specifically, reliability in the current market is guided by market participants acting to minimise the financial impacts of price volatility in the real-time market. This seeks to provide an economically efficient process for incentivising investment in the NEM and to deliver a standard of reliability at the lowest cost to consumers.

Scarcity pricing in the real-time market creates incentives for short term reliability responses to unexpected demand events and drives hedging behaviour by market participants.

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<sup>17</sup> Prof. Paul Joskow notes “The impact of the growing importance of this zero marginal cost generation further undermines incentives for decentralized investment in generating capacity that can efficiently provide these services (e.g. fast response turbines and batteries) as spot energy prices decline and imperfections in capacity markets and scarcity pricing mechanisms have a growing impact on investment incentives.” Joskow, P. “Challenges for wholesale electricity markets with intermittent renewable generation at scale: the US experience.” Oxford Review of Economic Policy 35 (2019): pp291-331.

While the NEM is often referred to as an 'energy only' market, it has always been constrained (by the market price cap, for example) and has a range of measures to smooth out the extremes for consumers and market participants. The reliability framework, explained below, focuses on the trade-off between the costs of reliability and an adequate supply of capacity.

In the NEM, resource adequacy is set around the reliability standard, which is a measure of unserved energy. The current standard is set at 0.002%, which means it is expected that, on average, up to 0.002% of demand might not be met in a specific region and financial year. Analysis by the ESB indicates that this is equivalent to having some involuntary load shedding once in every three years. The NEM has a range of market and regulatory tools to support this outcome:

- Reliability settings – a feature of the electricity wholesale market in the NEM designed to limit market participants' exposure to wholesale prices while delivering community accepted levels of resource adequacy.
- A real-time spot market – based on a "mandatory gross pool" design. This means generators must sell and retailers must buy all metered electricity output through the market. The spot market is supported by an ancillary services market, (FCAS and others) and a central clearing and settlement process to facilitate the efficient transfer of money between retailers, generators and network operators
- A financial contracts market – reduces market participant cashflow implications from spot price exposure and provides a smoother forward stream of revenue for underwriting investments. This market typically provides contracts of only two to three years duration, providing only a relatively short signal for underwriting new investments.
- Information – provided by AEMO to signal to the market where forecast gaps in resource adequacy may be expected (ESOO, Energy Adequacy Assessment Projection (EAAP), Medium Term Projected Assessment of System Adequacy (MT PASA), Short Term (ST) PASA, Pre-Dispatch (PD) PASA).
- The Retailer Reliability Obligation (RRO) – designed to support resource adequacy by incentivising retailers and some large energy users to contract for or invest in resources to cover their share of expected peak demand in regions and for times where there is a forecast gap.
- The RERT regime – used by AEMO to contract for additional resources outside of the spot market in advance of a projected shortfall.
- Directions and instructions from AEMO – AEMO can direct participants to increase or decrease output (or scheduled load consumption) to provide one or a combination of different services, including energy, market ancillary services, system strength, and other services.<sup>18</sup> Instructions have traditionally been used for load shedding (e.g. instructions to Transmission Network Service Providers (TNSPs)) and applied as a last resort action once all other options have been exhausted.<sup>19</sup>

In addition, there are reforms underway that will further support resource adequacy in the NEM:

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<sup>18</sup> Clause 4.8.9 of the NER provides for AEMO to require a registered participant to 'do any act or thing' when AEMO is satisfied that it is necessary to do so to maintain or return the power system to a secure, satisfactory or reliable operating state.

<sup>19</sup> While historic practice has been for AEMO to instruct for involuntary load shedding, clause 4.8.9 of the NER provides for AEMO to instruct any non-scheduled plant or non-market generating unit. Clause 4.8.9 instructions are not limited to involuntary load shedding, and the rules provide scope for AEMO to issue instructions to registered participants with respect to a non-scheduled plant which may include instructions to distributed batteries, solar PV and any other non-scheduled plant.

- Five-minute settlement (expected to start Q3 2021) will deliver sharper real-time price signals to support efficient operational and investment signals, particularly for flexible and dispatchable resources.
- Wholesale demand response mechanism (expected to start Q3 2021) is a transitional measure which will put demand response on equal footing with generation capacity, adding to the resources capable of providing resources at times of need.
- Reforms to the RERT (already in place) include the reinstatement of long notice RERT in June 2018 and enhancements to give AEMO greater flexibility in May 2019 to contribute to the delivery of resource adequacy by providing a more effective backstop mechanism for AEMO to draw on when necessary.
- An interim out-of-market reserve (expected to be in effect Q3 2021) allows AEMO to procure reserves under contract terms of up to three years, replacing long notice RERT. The volume of resources in the reserve will be those required to keep unserved energy to no more than 0.0006% in any region in any year for an interim period.

## How investment decisions are made

The current NEM framework typically incentivises investment through expectations of scarcity pricing in the future energy price. If market participants expect the future energy price to increase, more retailers, and large load, will buy financial contracts to cover their risk of high price exposure. This triggers an increase in the price of financial contracts and presents a price signal to attract investors to supply financial contracts. Parties that sell financial contracts can choose to 'back up' the financial obligation with generation or not. If it is backed up by generation then it has stimulated new investment. With this new investment, the price in the future energy market will reduce.

In order to respond to the price signals noted above, investors need confidence. The price signal in the contracts market provides a fair degree of confidence in the energy price for the next two years. To estimate the rate of return on an investment, investors forecast the expected revenue from the investment over the life of that asset. Different technologies rely on slightly varied forms of revenue streams from the NEM. To forecast, investors need to be able to predict, with varying degrees of certainty, the future supply and demand of the product or service. The degree of confidence in the forecast revenue stream impacts the riskiness of the project and therefore the required rate of return.

## Factors that may deter investment

Factors that can affect the business case and deter investment, causing a problem for resource adequacy in the future, are set out in Table 2.

TABLE 2 FACTORS THAT CAN DETER INVESTMENT

Missing elements of markets	Structural changes in markets	External factors influencing market outcomes
<ul style="list-style-type: none"> <li>• lack of dispatchable demand</li> <li>• incomplete markets</li> <li>• unpriced products and services</li> <li>• unpriced externalities</li> <li>• absence of long term price signals/ability to confidently forecast future prices</li> </ul>	<ul style="list-style-type: none"> <li>• increased variability of supply and demand</li> <li>• changing nature and cost of technologies and business models</li> <li>• Uncertainty re. Investment in transmission</li> <li>• uncertainty re. the timing of thermal generation exit</li> <li>• possibility and timing uncertainty of large load exit</li> <li>• uncertainty re. demand outlook</li> </ul>	<ul style="list-style-type: none"> <li>• policy uncertainty</li> <li>• government intervention including financial support for some projects.</li> <li>• global emissions policy sentiment</li> <li>• possible capital risk aversion</li> </ul>

Understanding the extent to which these factors are present in the NEM, and why, helps determine if reform to the RAMs in the NEM may be needed.

## Potential “missing elements” of energy markets

### Lack of dispatchable demand

Dispatchable demand refers to consumer demand that can be responsive within each dispatch period. Dispatchable demand could support efficient dispatch by modifying consumption in response to real-time prices.

Electricity demand has traditionally been relatively unresponsive to changes in electricity prices in real time.<sup>20</sup> However, more recently, steps have been taken in the NEM to change this with the introduction of a wholesale demand response mechanism. The potential to reward customers for their flexible demand is outlined in Section 8.1 on the transition to a two-sided market, and Section 7 on scheduling and ahead mechanisms.

In the absence of sufficient dispatchable demand to respond to prices, the emphasis in electricity markets is on generation and storage capacity to deliver resource adequacy in all periods, across all prices under the market price cap.

### Incomplete markets

Incomplete markets occur either when prices are unable to adjust freely or where there are other practical impediments to prices incentivising the appropriate short term and long term response from providers of supply and demand.

Price caps and price floors are examples of this. Caps are particularly relevant because if prices cannot rise sufficiently high for a sufficient period of time, the revenue received from the investments will not be sufficient to achieve the required return. However, allowing price caps to rise unconditionally can cause customer prices to rise to unacceptable levels and place risks on suppliers, given assets can fail to perform during high price events.

The risk of price volatility under the current market design drives participants to contracting and to financial markets where they can enter contracts to hedge uncertain spot price outcomes. The price and availability of those contracts depends on a number of factors including the caps on wholesale market prices.

### Unpriced products/services

The primary market signal in the NEM is for energy. However, to maintain a secure and reliable power system, more than just energy is required. These additional requirements, or services, need to be available to the system operator so that, alongside the dispatch of energy, sufficient essential system services (ESS) are provided.

The current NEM design has defined eight FCAS markets co-optimised with the energy market. It also has arrangements to procure some other services through non-market ancillary services (NMAS) and through regulation.

However, there remain a number of key services for the future which are not defined and priced through the current arrangements. The supply of resources that can supply these services, either on a standalone basis or in combination with energy and other services, is an important aspect of resource adequacy. These issues are addressed further in Section 6. Examples of ESS which

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<sup>20</sup> The 2020 ISP estimates there is approximately 440MW of demand response to price and network reliability programs across the NEM.

are currently not explicitly priced include fast frequency response (FFR), operating reserves, inertia and system strength.

Providing signals to investors about the value of these services to the system would allow market participants to take into account additional revenue streams when considering investments or retirements, and to invest in resources which may be able to provide a mix of energy and ESS. This is a complex undertaking, as a range of interrelationships exist between different ESS and energy. It can also be difficult to hedge shared services or find opportunities to contract with other parties to provide those services, or both.

### Unpriced externalities

Many externalities that exist in electricity markets may not be priced correctly (or at all). For example, carbon emissions are not explicitly reflected in price signals. Efforts to decarbonise the NEM are being stimulated through out-of-market incentives such as renewable energy targets, which disrupt the price signals in the NEM and may hinder achieving reliability objectives.

### Absence of long term price signals/ability to confidently forecast future prices

A possible shortcoming of the financial contracts market is that it has never evolved to be longer than two to three years duration. This does not provide a long duration price for underwriting new investments, many of which have a significantly longer period over which they are expected to earn sufficient revenue to justify the initial investment.

As ageing thermal generators exit, it may be that new investments are smaller in scale and are more suitable to the current, relatively short duration price signal. Conversely, it may continue to be difficult to secure Board approval for capital intensive new generation assets in the face of a very short-term financial market, uncertain demand, the risk of government intervention in the face of high spot/contract prices, and uncertain supply outlook in terms of timing of plant exit.

### Structural changes in the energy market

#### Increased variability of supply and demand

As VRE penetration increases in the NEM, a larger proportion of supply will be delivered by a generation fleet with output that is dictated by the weather rather than market incentives, leading to increased variability in the spot price at which the market clears. The increasing proportion of VRE lowers the average real-time spot price and increases price volatility.

This places pressure on the economics of assets in the NEM which rely on real-time prices for revenue streams. At the same time, many large scale thermal generators are coming to the end of their technical life. To date these generators have played a key role in operational supply and demand balancing and have provided important system services, therefore smoothing supply side variability.

To make the market even more dynamic, the demand side is becoming increasingly active, offering flexibility in electricity demand and/or producing energy through small scale DER. Any DER that does not participate in central dispatch processes is seen as a variation in demand that needs generation to flex to maintain grid stability. Visibility of this distribution level activity is still relatively low, and arrangements to provide DER with market incentives to operate in line with the physical needs of system are still developing.

### Changing nature of supply technologies and business models

Historically, resource adequacy was predominantly delivered by large scale, dispatchable generating units. However, rapid advancements in technology and a move to increased

renewable and variable energy resources are making the delivery of resource adequacy more dynamic and based on both the supply and demand side.

Different business models, commercial operating strategies and contracting arrangements are emerging. The sheer speed and volume of these changes makes weighing up commercial opportunities and risks to inform operational and investment decisions a more complex equation. This may mean it is safer for potential investors to wait to invest when technology options and costs are more certain than would be the case today.

### Uncertainty with the timing of thermal generation and large load exit

The biggest resource adequacy challenge the NEM currently faces is how to maintain security and reliability through the retirement of a significant proportion of the existing fleet of thermal generators. These assets are currently relied on to balance the system at relatively low and stable cost and maintain reliability (Section 2.3 and Section 5).

Another factor that adds to this complexity is that demand for electricity is flat, with potentially large load exits looming. Investing into a market where demand is increasing provides certainty; even if investment timing is a little wrong, the investor knows revenue can catch up and cover the error over time. Large scale exits of thermal generators are likely to lead to sharp increases in the energy price, particularly during periods with low wind and sun. Conversely, removal of large, relatively stable intra-day loads will place sharp downwards pressure on energy prices. Generators are currently unable to effectively hedge the risk that large load may exit, which could deter prospective investors or current owners from re-investing.

Given flat current demand and the related risk of large loads exiting, investors may need additional certainty in the forecast of future prices. Therefore, understanding how the thermal exit impacts the current price signal in the 'energy only' market is important.

It is also important to recognise how the exits of thermal generation impact on government priorities, and the communities that depend on these assets. Uncertainty around the timing of exit of thermal generators, the circumstance of their exit and the timing of replacement capacity are complicating factors around future investment decisions for dispatchable capacity. The risks associated with an ageing thermal generation fleet retiring are discussed in Section 5.

### External factors influencing market outcomes

#### Policy uncertainty and government intervention

Structural changes in the sector are typically exacerbated (or caused) by policy interventions and uncertainty. A key theme in stakeholder responses to the issues paper was the unfavourable effect policy uncertainty has on investment incentives in generation resources. Participants noted that the risk of government intervention has intensified since 2017, that there have been various interventions at both state and federal levels, and that even discussions and "threats" of intervention may deter investors.

Specific market uncertainty arising from government interventions, both in the NEM and overseas, was also noted:

- Market price caps have been set too low, and investments in resources have been deterred to contribute to meeting the socially optimal level of reliability.
- Direct subsidies to specific generators can lead to changes in dispatch outcomes and trigger the need for further intervention.
- Policies do not align with incentives to encourage investment in the amount and type of resources that would meet consumer and power system needs.



The current design of the NEM may result in saw-tooth wholesale prices, whereby sharp increases and decreases could result from block thermal exits and large load exits. The volatility in prices, particularly increasing prices, has triggered multiple federal and state government interventions. This is discussed in more detail in Section 5.

Further, governments may have a lower cost of capital and a higher risk appetite or different objectives (e.g. reducing reliability risks and/or reduce emissions) that move them to invest ahead of the private sector. However, the more governments subsidise new generation (if the cost of that generation net of the subsidy is below existing generation), the more this will depress spot prices and forward contract prices, which may undermine private investment signals.

The key question related to resource adequacy is whether the investment incentives in the NEM will maintain reliability at the lowest cost to consumers within an environment of continued government intervention. Some stakeholders suggested that market incentives must be much more attuned to the role governments will play in facilitating the transition and the investment required, as well as each jurisdiction's policy priorities.

### Capital risk aversion

It is possible that capital is becoming more risk adverse than it has been historically. Other jurisdictions outside the NEM have taken steps to de-risk their markets. The potential impacts on the cost of capital in the NEM and the willingness of investors to invest in long lived resources needs to be evaluated.

### Global climate change sentiment

Community and corporate action to invest in low emission energy resources is driving investments based on factors other than just meeting demand of consumers and the engineering needs of the power system. This, in turn, impacts the ability of the market and system to deliver resource adequacy, if the structures and tools in place are not the only drivers of investment in the power system.

## 4.2. What are the options considered?

As discussed above, the current NEM relies on scarcity pricing driving sustained high prices alone to encourage investment. The interdependent relationship between spot prices and financial contract prices provides an efficient market response to stimulate investment based on minimising participant price risk. This framework relies on and responds to price volatility and the future expectations of the energy price.

The ESB is proposing to consider options that enhance this price signal and make real-time prices as reflective of the needs of consumers and market participants as possible.

Given the risks noted above, scarcity pricing may not be sufficient to stimulate investment to meet government and community expectations of reliability, particularly during the transition away from coal-fired generation. As a result, the ESB is proposing to consider options that could create a longer duration price signal for dispatchability or capacity that may be separate from future expectations about the spot energy price.

Further, given the intense operational variability we expect to see in the NEM through and after the transition, backstops, while they should remain only as emergency responses, need to be ready to respond to sudden and unexpected situations. Given this, the ESB is also proposing to consider whether RERT processes and the interim reliability reserve are as efficient and effective as possible.



For resource adequacy post-2025 in the NEM, the ESB considered whether:

1. Real-time prices need sharpening so spot prices better reflect the cost of reliable, secure supply.
2. Investment signals need strengthening through longer duration price signals.
3. Backstops need to be more efficient or effective, which may involve additional assurances where needed to support reliability (and security) under extreme circumstances and where the market does not deliver within reliability standards.

In the sections below, we explore specific options under these categories. As these options are considered, the allocation of risk is critical. The current market design, which relies predominantly on the forward energy price to provide reliability, places the risks of over-investment in capacity on the investor. The risks of under-procurement sit with consumers, through reliability issues and RERT/interim reliability reserve costs.

The introduction of the RRO, using financial contracts, slightly shifted the risk of under-procurement onto retailers and large load, through penalties on failing to contract sufficiently. Shifting the RRO to physically backed qualifying contracts or implementing a decentralised capacity market (as discussed below) shifts the risks further. It would move a portion of over-procurement risk to consumers, and place a portion of under-procurement risk on generators and retailers. Understanding how the risk profile is allocated to provide a least cost, reliable power system is an important consideration for resource adequacy into the future, and one on which the ESB would value stakeholder feedback.

On the flip side, the introduction of a scarcity price adder or operating reserve (as discussed below) would give the market operator the ability to provide an additional incentive mechanism to capacity at times of scarcity. As these additional revenues are the product of an artificial demand curve derived by the market operator, there is an increased risk to consumers that they are over-paying for a given level of reliability.

FTI Consulting provided advice to the ESB that assessed seven different options potentially available to the NEM to further support resource adequacy. The report did not evaluate how effective these options will be given the characteristics of the NEM, nor give explicit consideration to issues related to the absence of longer-term price signals, the ability to confidently forecast future prices or the likelihood and impact of government intervention. Evaluating and determining these will be the task of the ESB, with support from stakeholders. Further detail can be found in FTI's final report to the ESB, provided on the ESB Post-2025 program website.

### Options to sharpen the real-time market – an operating reserve mechanism

An efficient real-time price will help leverage asset investment that best responds to the needs of consumers and the power system. This is important, irrespective of the mechanism for encouraging investment in the NEM. Having a real-time price that accurately reflects consumer value is very closely linked to identifying and valuing ESS, as discussed in MDI – C.

As noted, the current investment signal for reliability uses expectations of high future prices to encourage hedging behaviours, which in turn incentivises generation investment. If sharpening the real-time price results in increasing the price during times of scarcity, this will strengthen the current investment framework, which relies on future expectations of high prices to trigger investment, and hence reliability. In particular, it will provide stronger incentives for resources that are able to respond during times of scarcity, such as storage or flexible dispatchable resources – provided investors have the capacity to accurately forecast these future prices and have sufficient confidence that governments will not intervene in the market and undermine these higher prices.

Three options that seek to sharpen real time prices were considered:

1. A scarcity price adder, which increases the real-time energy price using a manually applied price adder during periods of scarcity to reflect requirements for responsive capacity.
2. An operating reserve mechanism that establishes a service-based operating reserve market, co-optimised with energy to increase the real-time energy price.
3. Adjustments to the reliability settings (market price cap, price floor and cumulative price threshold, including the administered price cap), which could increase participants' risk exposure and provide greater incentives to maintain resource adequacy.

As discussed above, reliability in the market is guided by market participants acting to minimise the financial exposure in the real-time market. The price and availability of financial contracts supports generation investment, and depends on the market reliability settings. Increasing the Market Price Cap, for example, would increase the riskiness of the NEM for market participants. This would encourage participants to change the price and availability of financial contracts to help them hedge this increased risk. The trade-offs and implications of increasing the riskiness of the NEM is reviewed every four years by the Reliability Panel.<sup>21</sup>

The scarcity price adder concept and potential adjustments to the reliability price setting are explored in detail in FTI's report provided on the ESB Post-2025 program website. Scarcity pricing exists in the NEM "implicitly", as even without dispatchable demand, resources can freely offer bids above variable cost up to the Market Price Cap. This means market participants have an incentive to invest and make available their capacity when there is financial opportunity. A formal scarcity pricing mechanism in the NEM could shift this implicit scarcity pricing effect to an explicit mechanism with a more transparent demand curve for reserves. Increasing spot prices for existing levels of scarcity would raise contract prices and support more investment.

An operating reserve mechanism or market, in its broadest sense, is a mechanism whereby a central buyer explicitly procures and prices reserves. This increases the real-time energy price during periods of scarcity and reflects requirements for responsive capacity (capacity that can respond at very short notice to variations in supply and demand). An operating reserve does not create a separate reliability investment price, but does provide real-time price signals if the market needs resources quickly installed that are less capital intensive.

In the NEM, "reserves"<sup>22</sup> refers to surplus or unused capacity from generating units, scheduled network services, and the ability to reduce demand. In practice, this means reserves are represented by generators or demand response providers that offer their availability into the wholesale market, but are not dispatched (i.e. not actively engaged in supplying bulk energy for the relevant time period for part or all of their capacity).

Reserves can be "in market", i.e. generators that are available to run, have bid into the wholesale market but are not called on to run. Reserves can also be "out of market", i.e. the emergency reserves AEMO procures through the RERT mechanism to be on standby. This spare capacity can be used to manage uncertainty in the power system.

"Operating reserves" are currently not specifically defined in the NEM, but the term alludes to specific amounts of surplus or unused megawatts, with specific characteristics, that could be identified, valued and traded to fulfil a specific power system need. Operating reserves are

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<sup>21</sup> Reliability Panel responsibilities can be found here: <https://www.aemc.gov.au/our-work/developing-electricity-guidelines-and-standards>

<sup>22</sup> Chapter 10 of the NER defines the following terms - **Reserve**: Scheduled reserve or unscheduled reserve. **Scheduled reserve**: The amount of surplus or unused capacity: (a) of scheduled generating units; (b) of scheduled network services; or (c) arising out of the ability to reduce scheduled loads. **Unscheduled reserve**: The amount of surplus or unused capacity: (a) of generating units (other than scheduled generating units); or (b) arising out of the ability to reduce demand (other than a scheduled load). The NER does not define operating reserves.

currently supplied by participants as part of their risk management activities. These reserves are monitored by AEMO, which has the power to intervene if inadequate reserves are available.

Given operating reserves are ultimately spare megawatts, they can be provided by supply or demand response capacity and could be online and “spinning” or offline, as long as they can be available within the required timeframe.

Operating reserves could encompass a whole range of “reserve products” defined by the characteristics of the megawatts (e.g. flexible, dispatchable, ramping), the timeframe over which they are made available (seconds, minutes, hours), or the type of event/occurrence they are being used to respond to (e.g. security, reliability or transitional concerns).

Depending on the definition, operating reserve products can be akin to other system services and be valued and traded that way. As discussed in Section 6, this may address some of the security needs of the power system as it reflects requirements for responsive capacity (capacity that can respond at very short notice to variations in supply and demand).

The operating reserve mechanism is outlined in Table 3 below.

An operating reserves mechanism requires co-optimisation of energy and reserves. This would require the handling of new dispatch bids, constraint equations and other software changes within AEMO (and in turn, within the suite of tools that market participants use to form market strategies over short and long-term horizons). The fact co-optimisation of FCAS already takes place in the NEM may make implementation of a co-optimised reserve market less complex in the NEM than in some US markets where the system changes have been costly.<sup>23</sup> However, like all reserve markets, there will be significant administrative overheads and a centralised process or body would be required to determine the price schedule. There are challenges with this, similar to the challenges associated with setting a volume in a decentralised capacity market (explored below), both of which would require resources to monitor compliance with qualifying and operational rules.

TABLE 3 OPERATING RESERVE MECHANISM

<b>A (co-optimised) operating reserve market, which is a system service-based RAM</b>	
<b>Product description</b>	Operating reserve products (one or more) that are defined in the system design and co-optimised with energy is dispatch and pricing.
<b>Obligation</b>	Depends on the specified OR market design.
<b>Procurement approach</b>	Central body (ideally a body representing consumer interests and accountable for their outcomes) would determine the principles to be used by the System Operator (SO) to periodically determine the Operating Reserve Demand Curves (ORDCs).
<b>Enforcement</b>	Enforcement regime akin to other market services such as FCAS.
<b>Pricing</b>	Can have a significant impact on market prices – depends on design of mechanism.
<b>Underlying premises</b>	Reliance on the co-optimised prices of energy and reserves to deliver (over time) the desired level of reliability by providing incentives for market participants to invest in capacity. It would especially incentivise investment in capacity which meets the responsiveness and dispatchability characteristics required to participate in the operating reserve market. Requires willingness and ability to tolerate periods of high prices and low reserves as the market response develops, and willingness to centrally determine and procure required levels of capacity in real time.

The ESB is proposing to further consider an operating reserve for the NEM to improve operational signals to resource owners to supply the right amount and type of resources where and when they are needed. There is a trade-off in determining the right amount and type. For example, with FCAS, the Reliability Panel determines the frequency standard on an economic basis and AEMO sets the demand curve for those services consistent with it.

<sup>23</sup> Across US independent system operators (ISOs) that have implemented scarcity pricing, the majority have implemented an operational reserves mechanism rather than a scarcity price adder (i.e. taking the view that the benefits outweigh the additional complexity).

Providing extra revenue streams for offering reserves into the market may, over time, support investment in resources that can deliver reserves, through:

- Short term operational signals – explicit valuation of different reserve products and levels of reserves in real (or closer to real) time enables prices to rise according to the degree of scarcity at that time. This will signal the market to supply additional energy and reserves, and/or consume less energy.
- Longer term investment signals – if demand for operating reserves goes up, the energy price may also increase, which in turn will stimulate higher expected future energy prices, and thereby higher contract prices. Higher contract prices, combined with predictable demand and supply of reserves into the future, signal greater opportunities for investors to invest. However, this assumes the market can confidently forecast future prices and investors are confident governments will tolerate these higher prices and will not intervene and undermine price signals. If bundled with the price of energy, this could significantly complicate contract markets and negatively impact liquidity and therefore investment.

An operating reserve would not provide a separate price for reliability or lengthen the duration of signals for investment. It may therefore only provide incremental improvements to current incentives for investment in dispatchable resources.

An operating reserve as a RAM would only be developed in conjunction with the work outlined in the Essential System Services Section 6 – that is, the ESB is not proposing separate operating reserves for reliability and for system services.

### Options to strengthen signals for investment – an expanded RRO or decentralised capacity market

As discussed above in Section 4.2, the ESB is considering whether an efficient energy price sets a necessary and sufficient signal for investment. Given the range of future challenges outlined in this section, and stakeholder views on the difficulty in making the case for investment in firm resources, it may be that high and volatile prices coupled with a lack of timely investment decisions by the private sector is not in the long-term interests of consumers. As such, an efficient energy price may be necessary, but not sufficient to deliver the reliability expectations of the community and government.

FTI assessed three options that seek to strengthen longer term price signals:

- (1) Modified RRO – adjustments could include removing the trigger so the RRO is ‘always on’, tightening the measurement of firmness, stricter enforcement before T-1, or increasing the level of penalties. These adjustments would increase the level or further strengthen retailers’ incentives to contract with resources.
- Capacity markets – this option would set capacity or reliability as a separate commodity to energy. It can be:
  - (2) Centralised, whereby the amount of procurement and the procurement itself is determined by a centralised body. The amount may be for all expected market capacity, or another predetermined amount.
  - (3) Decentralised, which is distinct from a centralised market in that obligations for capacity procurement are placed on market participants, and can be defined by the market participants themselves to meet reliability obligations and the obligations can be defined in financial or physical terms.

Below is further exploration of the concepts of a modified RRO (which with physical contracts can be thought of as a type of decentralised capacity market) and a decentralised capacity market. (For more on a centralised capacity market, see FTI’s report on the Post-2025 program website.)

## Modified RRO

Adjustments could include removing the trigger, tightening the measurement of firmness, stricter enforcement before T-1, or increasing the level of penalties. These adjustments would increase the level or further strengthen retailers' incentives to contract with resources.	
<b>Product description</b>	Retailers required to hold a portfolio of qualifying contracts
<b>Obligation</b>	AEMO to determine, for each region, the potential future shortages and their duration. Retailers (and large energy users) to enter into the qualifying contracts to meet the "one-in-two year" peak demand.
<b>Procurement approach</b>	AEMO identifying the shortfalls and triggering the RRO, AER to issue requirement to enter qualifying contracts or to disclose net contract positions. Retailers' responsibility arises once the scheme is triggered in a particular region over a specified time period. Retailers then take their own actions to procure.
<b>Enforcement</b>	Retailers face costs when there is an actual shortfall and they have failed to meet obligations – reflects costs AEMO incurred for any action.
<b>Pricing</b>	Contract prices reflect the market's view about future spot prices – likely to be a reduction in market price and volatility over longer term.
<b>Underlying premises</b>	Requires a willingness to "centrally" assess and monitor potential future shortfalls in resource adequacy, and address those shortfalls indirectly with a financial market mechanism.

## Decentralised capacity market

Obligations on retailers to procure capacity (rather than it being centrally procured). That capacity might be defined in financial or physical terms.	
<b>Product description</b>	Tradeable units of resources – e.g. financial contracts or capacity certificates which must be procured by market participants.
<b>Obligation</b>	Retailers, or large load, to procure products to meet a demand level or reliability outcome that may be administratively determined or based on market forces.
<b>Procurement approach</b>	Retailers procure the quantity while a central body (e.g. the SO) needs to define the products that retailers are obligated to procure.
<b>Enforcement</b>	Contract sellers bound to deliver and retailers bound to comply, holding the coverage required. There are options on the extent to which retailers make decentralised decisions for which they are held responsible during shortfalls through to greater central specification and penalties for non-delivery.
<b>Pricing</b>	Market based and will introduce a separate price for reliability or capacity which is additional to real time prices. <u>Duration can be specified. Usually spot market price caps would also be reduced as the same scarcity price signal is no longer required.</u>
<b>Underlying premises</b>	That some capacity in a reliable power system is only used very rarely and without a separate revenue stream or allowing unacceptably high real-time prices, will not be provided by the market.

The fundamental aim of these mechanisms is to either push the current energy price signal 'harder' by enforcing financial contracting compliance, or create a separate price signal for reliability or capacity. The aim of both is to provide a level of insurance that enough capacity exists to meet demand. In the case of a decentralised capacity market, policy makers would have more direct control over the price signal for reliability and the duration of the signal.

Both the RRO and the decentralised capacity market aim to deliver on reliability expectations and do this by placing a primary obligation on retailers to provide this reliability insurance. Retailers do this by demonstrating they have procured products to meet a demand level or reliability outcome that is administratively determined. If the market is not in a supply and demand balance, and reliability issues present themselves, retailers or large load are required to face penalties and pay a portion of RERT.

Given the enhanced focus on reliability or capacity procurement of the RRO and decentralised capacity markets it is unlikely that an RRO with financial qualifying contracts would need to sit alongside a physically backed decentralised capacity market. An RRO with physically backed contracts is a form of decentralised capacity market. Either an enhanced RRO or a decentralised capacity market could co-exist with an operating reserve as well as the other RAMs currently in the NEM.

The current RRO supports reliability in the NEM by encouraging retailers and some large energy users to contract or invest in resources sufficient to meet the Reliability Standard for their own or their consumers' load. If AEMO identifies reliability gaps and this leads to the RRO being triggered, AEMO procures on-demand (RERT) resources sufficient to cover the magnitude of the gap for the period of the shortage. Retailers can buy and sell contracts to cover their share of peak demand.

If the market response is insufficient (actual demand exceeds that which would have been expected to occur one in every two years) and AEMO has procured RERT resources to cover the expected gap, then retailers and some large energy users in breach of their reliability obligations will pick up a greater share of RERT costs and could be liable for civil penalties too.

A key market design feature required for the RRO to work effectively is well-functioning and efficient financial markets that can produce investment in physical resources, if required. Any expansion of the settings would need to ensure alignment between contracting behaviour, its impact on the spot price, and the physical needs of the system; that is, it would need to ensure higher contract prices resulted in improved incentives for investment and resource availability during periods of scarcity. While the RRO and its enhancements would require retailers to hold financial contracts against their load profile obligations, decentralised capacity markets would require contracts which are more closely linked to physical capacity.

A decentralised capacity market also puts an obligation on retailers to procure products to meet a demand level or reliability expectation that may be set by a central body (e.g. governments or the system operator) or determined by market forces. Decentralised capacity markets can also place obligations on the sellers of contracts to improve confidence that the resources will be there when the market needs it. Like the RRO, decentralised capacity markets require detailed consideration of key factors like eligibility, whether specific types of capacity are targeted, timings of procurement, the length of the investment signal, and penalty levels. Decentralised capacity markets would introduce a separate price signal for reliability and capacity, as noted above.

The fact that policy makers can set the form and adjust the length of the price signal to closely meet reliability outcomes is a key rationale for considering a decentralised capacity market. These features offer policy makers greater assurances that investment in capacity will be forthcoming. However, the dynamic between the real-time energy price and this reliability price signal then becomes critical, as inefficiencies arise if market participants seek to arbitrage between the two.

There are various ways the volume of required capacity can be defined, but two possible approaches are:

- A specified MW amount for each retailer.
- An amount representing each retailers' peak demand plus a margin.

There is also a wide spectrum of definitions for the obligations, e.g. the obligations may or may not be binding at all times.

This differs from a centralised approach because retailers decide how to meet the obligation (e.g. with their own contracting / hedging approach) and this reliance on the market can in principle be more efficient than a centralised approach where the operator typically makes such a decision.

Decentralised capacity markets also have the ability to place obligations on generators, or the sellers of supply side contracts. This is how a level of under-procurement risk is placed onto generators. If retailers are obligated to ensure they have purchased sufficient contracts to maintain desired reliability levels, then sellers of the physical contracts need to meet performance obligations. If the market hits reliability issues in real time, either a retailer or generator did not 'perform' as expected, and penalties will apply. This dynamic needs specific consideration given the exit of ageing thermal generators and the importance of price signals to notify the market of their exit.



The ESB could look to expand the RRO along the continuum towards a decentralised capacity market in the following ways:

- Remove the trigger so the RRO becomes a continuous obligation on retailers.
- Fine-tune retailer obligations, for example to hold sufficient contracts to cover a one-in-10 year (rather than the current one-in-two year) event, or to cover a level of reserve margin in certain scenarios.
- Adjust the criteria for qualifying contracts, for limiting the types of contracts (or a portion of contracts) which can be used through to requiring them to be physically backed.
- Strengthen the compliance framework, e.g. by increasing the regularity of compliance checks or the criteria for compliance.

The more an RRO is expanded, the more it becomes a decentralised capacity market. For example, an RRO that becomes “embedded” in market expectations, has no trigger, and requires contracts that have physical backing, is a decentralised capacity market.

Expanding the RRO or implementing a decentralised capacity market would support resource adequacy by encouraging more long term financial or physical contracts to support the cheapest form of investment before coal-fired plants exit, thereby minimising the risk of government intervention during the transition. It would also make it obvious if large load was about to vanish by providing stronger incentives for retailers to contract for at least a year.

When considering the options to expand the RRO or introduce a separate price for reliability through a decentralised capacity market, the ESB will focus on whether the adjustments would strengthen investment signals sufficiently to cause a change in participant behaviour that results in greater levels of resource adequacy, especially during times of scarcity. The ESB will also consider the shift in risk allocation and whether this promotes the long-term interests of consumers by keeping prices as low as possible through the transition and beyond.

### Consequential changes to backstop mechanisms – RERT and interim reliability reserve

Most liberalised electricity markets have some form of backstop, applied under extreme conditions when all resources have been used. Such mechanisms are not intended to be a substitute for the resource adequacy formed through a well-functioning electricity market.

As an “out-of-market” measure, backstop mechanisms can undermine the operation of the wholesale market in delivering energy and ESS, and reduce the role for market-driven investment, ultimately imposing significant costs for consumers.

Policy makers in some markets have sought to use backstop measures to manage extreme events to secure reliability beyond what might be expected under the reliability standard. A backstop mechanism can also theoretically be relied on more heavily as an interim measure to assist with bringing new resources online as a new market design is implemented.

The RERT is a form of “backstop” in the NEM to support reliability in extreme circumstances. As a last-resort measure, the RERT would typically be used when all other RAMs are insufficient to meet reliability requirements. Therefore, the introduction of additional RAMs (or adjustments to existing ones) that would improve the delivery of resource adequacy, if successful, would likely reduce the need (less often and lower volume procured) for the RERT.

The introduction of different RAMs may also lead to the reduction of different types of RERT contracts and the need to deploy them. This would enable more in-market resources to be appropriately rewarded for the reliability value they provide to the market. For example, with an operating reserve market that responds to the real time needs of the market, short-notice RERT contracts would be less likely to be needed, whereas an expanded RRO or capacity market, would likely see less long-notice RERT contracts needed, due to certainty from the additional capacity procured in advanced through the capacity market. For example, an operating reserve



market or an expanded RRO or capacity market by increasing resources available to the market, less then need for both short and long notice RERT contracts.

If an additional RAM was introduced, the ESB would consider the implications this new mechanism is likely to have on the design of the backstop mechanism.

As the NEM transitions to greater reliance on variable resources, it may be that the nature of resources comprising backstop mechanisms need to change to deal with low probability but high impact events such as weather dependent resources suffering periods of sustained low capacity factors, during which time storage in the NEM is depleted.

Improving government and community confidence that resource adequacy will be delivered by market and regulatory frameworks

A number of stakeholders have suggested that the ESB should consider how resource adequacy in the NEM can be adjusted or implemented to reflect the priorities and preferences of individual NEM jurisdictions. This will be important context when designing the right mechanism for the national framework.

It is not possible to design a resource adequacy system that is flexible and reflective of all possible jurisdictional priorities and programs. However, the options outlined in this paper. in addition to existing mechanisms. give governments the opportunity to assess if their broader policy priorities are met by or complementary to the design of the NEM.

For each additional RAM considered, there are opportunities for governments to consider if key policy priorities can be reflected through the nature of obligations placed on retailers in an enhanced RRO or decentralised capacity market, or through the qualifying requirements for participation in an operating reserve.

A key consideration for governments will be if the RAMs adjustments canvassed in this paper give greater confidence that resource adequacy will be maintained through the energy transition, and require fewer “out of market” programs and government interventions.

In designing future programs, the ESB encourages governments to leverage the risk and incentive structures built into the current (and future) framework design and analyse the impacts of any regionally targeted policies on the NEM as a whole.

Where additional out of market programs are designed to drive investment in certain resources, existing frameworks and incentive structures should be leveraged wherever possible. The ESB would like to understand if a modified RRO or decentralised capacity market, as outlined above, could be further adjusted by jurisdictions to meet jurisdictional renewable energy targets or other energy related policy priorities.

In considering regionally based policies to support resource adequacy, governments should also be mindful of NEM-wide impacts. This could include notifying<sup>24</sup> the National Energy Cabinet of proposed regionally based actions or policies and seeking advice from market bodies about the potential implication of such policies. This could support greater accountability and transparency to the community on the likely impacts of a government’s action.

#### 4.3. Which options are proposed for further development and consideration?

With no change to current arrangements, the volatility of spot prices is likely to increase as the NEM transitions – particularly as VRE and DER make up a growing proportion of the energy mix.

Investors will also continue to face uncertainty – at least for a transitional period of time – driven by structural changes within the market and power system, and external factors that impact

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<sup>24</sup> Reference clause in AEMA that alludes to notifying colleagues if taking unilateral action

sector outcomes. This uncertainty will in turn, continue to challenge investors' ability to bank on revenue streams to support their business case.

In considering the need for RAMs, the ESB will look to ensure the real time market design is fully reflective of the system's needs by ensuring, where possible, unpriced services are valued by market mechanisms (see section 6) and flexible customer demand is increasingly responsive to supply (see section 8 – two sided markets). The real-time market design is critical to arrange for reliable and efficient delivery of resources precisely when they are needed.

However, it may be that the expectations of high energy prices alone are insufficient to drive the investments required to meet socially optimal levels of reliability or that governments are unwilling to allow the sustained high prices required, or both. This is why the ESB is also considering whether an enhanced RRO or decentralised capacity market can work alongside potentially lower real-time price signals to support resource adequacy. Developing an enhanced RRO or decentralised capacity market may provide the market the necessary confidence and reliability obligations needed to ensure resource adequacy can be maintained as we progress to a low-carbon energy future. RAMs cannot completely "solve" all underlying market issues, but the ESB thinks new or adjusted RAMs could address (at least in part) the investability challenge faced by participants and investors.

As such, the ESB sees value in exploring RAM options that strengthen both short-term and long-term investment in resources that are available to meet the power systems physical needs.

The ESB will therefore look to explore in more detail the following options:

1. An operating reserve mechanism or market<sup>25</sup> to complement the work being done to value unpriced services and to make demand more responsive to supply. The ESB sees merit in considering this option as a way of potentially enhancing the real-time price to better reflect the cost of reliable, secure supply.
2. Expanding the RRO, as outlined above, or introducing a price for reliability through a decentralised capacity market. The ESB sees merit in considering a range of options along this spectrum as a way of potentially strengthening signals for investment.
3. Consequential adjustments to the RERT or interim reliability reserve depending on the other RAMs implemented. The ESB sees merit in considering whether changes are needed to retain effective backstop/s in the market, noting that the use of backstops should be minimised where possible.

The ESB will not seek to explore the following options further, unless stakeholder feedback provides compelling reasons that these options provide long term benefits to customers in a post-2025 NEM:

- Reliability standard and settings – the ESB considers the current process whereby the Reliability Panel has responsibility to regularly review and (where relevant) recommend changes to the Reliability Standard and settings remains appropriate. The ESB notes that the Panel will start its next regular review in early 2021.
- RERT – the ESB notes that the RERT has already been adjusted several times in recent years, including by amending it to accommodate the interim reliability mechanism, and agrees with FTI that the benefits of further adjustments are limited. Consequential changes to the RERT may be needed should other RAMs be implemented.
- Scarcity price adder – the ESB does not see value in exploring this administrative option given it seeks to achieve the same outcomes as an operating reserve mechanism but with

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<sup>25</sup> The ESB notes that the AEMC is currently considering three rule change requests relating to reserve provision in the NEM. Each rule change proposal offers a different model of operating reserve mechanism for consideration. The AEMC is working closely with the ESB and the other market bodies as it progresses these rule change requests.

reduced efficiencies and benefits. In addition, the implementation simplicity of a scarcity price adder (as compared to operating reserve mechanisms) experienced in other markets is not relevant in the NEM context, given co-optimised markets are already in place for FCAS.

- Centralised capacity market – the ESB does not support this option in the NEM context. It translates to a more fundamental shift in risk allocation and does not utilise the markets ability to innovate and compete to keep prices as low as possible, and there is limited evidence of its success overseas. Further it presents no obvious benefits over a decentralised capacity market.

#### 4.4. Questions for consultation

1. Do you have views on whether the current resource adequacy mechanisms within the NEM are sufficient to drive investment in the quantity and mix of resources required through the transition?
2. Do you have views on whether the short-term signals provided by an operating reserve mechanism or market would provide adequate incentives to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What impact could an operating reserve have on financial markets? What are the benefits of this approach? What are the costs and risks?
3. Do you have views on whether the signals provided by an expanded RRO based on financial contracts or a decentralised capacity market would provide the type of incentives participants need to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What are the benefits of this approach? What are the costs and risks?
4. Do you have views on how an operating reserve mechanism and/or expanded RRO would impact the need for and use of RERT and the interim reliability reserve if they were introduced into the NEM? What adjustments to the RERT and/or interim reliability reserve may need to be made so that they are complementary and not contradictory or duplicative?
5. Do you have views on how RAMs (current or future) can better be integrated into broader jurisdictional policy priorities and programs? Should jurisdictions reflect broader policy priorities through the nature of obligations placed on retailers in an enhanced RRO or decentralised capacity market, or through the qualifying requirements for participation in an operating reserve?

## 5. AGEING THERMAL GENERATION STRATEGY – MARKET DESIGN INITIATIVE B

### Key points

With 61% of the existing thermal generating resources in the NEM likely to exit over the next two decades, it is essential for reliability of supply and prices that this transition is orderly, and delivered at least cost to customers.

These exits are not unexpected, and the current regulatory framework has many safeguards to ensure reliability can be maintained at lowest cost, following capacity exits.

However, the scale, speed and nature of the replacement technology is unprecedented in the NEM. Therefore, correctly identifying the risks, understanding them and developing a holistic market design will support a transition at lowest cost to consumers. This is at the centre of the ESB's market design project.

The work underway to develop frameworks for ESS, support active participation by consumers, and recommend an optimal mix of signals for investment in the NEM will reduce the risks of unnecessarily high costs to consumers as the coal-fired plants exit.

This section will also carefully consider whether there are risks specific to the exit of coal-fired generators that effective market operations may not be capable of addressing.

We seek feedback from stakeholders on the risks associated with coal-fired plant exits, and whether the current regulatory framework is sufficient to address them. These include whether there are specific risks other MDI workstreams must consider and respond to, to ensure consumers do not pay more than necessary as the coal-fired plants exit, and whether there are 'residual' risks that an effective NEM design may be incapable of solving efficiently, what are they and how they could be resolved at lowest long-run cost to consumers.

### 5.1. What is the problem this initiative is addressing?

The scale, speed and nature of the changes in the generation fleet in the NEM have never before been experienced in the NEM's history. The NEM started with 33GW of largely coal-fired generation. Some new coal plants entered between 1998 and 2004, but more recently coal has been exiting, with around 4 GW of black and brown coal capacity leaving the market since 2014.<sup>26</sup> Today there is 34GW of coal-fired generation in the NEM.<sup>27</sup>

Given the NEM infrastructure was originally designed with larger, synchronous plants in mind, of which coal-fired plants was a large portion, consumers and operators are currently dependent on these generators for system security services, reliability and a cheap form of energy when coal prices are relatively low.

Over the next 20 years, it is expected that approximately 15GW of large thermal plants will reach the end of their technical lives and likely exit the NEM.<sup>28</sup> These exits are driven mainly by a lack of viability, for a combination of two reasons; ongoing costs (including maintenance costs) have become too high as the plants age, and forecast revenue has become too low due to competition from low priced VRE, driven by government policies to reduce emissions.

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<sup>26</sup> AER, State of the Energy Market 2020, page 92; Gilmore and Simshauser, Is the NEM Broken? Policy discontinuity and the 2017-2020 investment megacycle, May 2020, p8 and p9

<sup>27</sup> AEMO, ISP 2020

<sup>28</sup> AEMO, ISP 2020, p12

To account for these plant exits, the ESB's deliberations on a market design have a strong focus on maintaining reliability, security and affordability through the transition and then as part of the future structure.

The aim of this MDI is to engage with stakeholders on the risks of inefficient outcomes of ageing thermal generation exits and whether current regulatory arrangements and other reform measures are likely to address these risks. Following further analysis and input from stakeholders, if the ESB forms the view that there are significant risks that may be addressed by regulatory change, then options will be investigated.

The exiting thermal fleet (see Figure 11) is expected to be replaced with 26-50 GW of new large scale VRE (in addition to existing, committed and anticipated projects), supported by between 6GW and 19GW of new flexible and dispatchable resources. The 2020 ISP highlights that total system costs for the NEM over 2021 to 2042 has a present value of \$86 billion.<sup>29</sup> Given the amount of investment that needs to occur, and the potential impact on wholesale prices as resources enter and exit, market arrangements need to be carefully considered to ensure the transition is lowest cost for consumers in the long term.

The technical needs of the power system must continue to be met as the structure of the system changes with the introduction of new generation with significantly different operating characteristics from the existing fleet. Such a restructuring of the generation fleet presents significant uncertainties and risks for reliability, security and affordability.

Uncertainty around the timing of exit of ageing thermal generators could have a significant impact on the affordability of electricity. This uncertainty could result in replacement capacity being delayed or new investments requiring a higher return on capital. This could lead to higher electricity prices. This uncertainty is also reflected in the level of transmission investment required under the ISP.

Premature exit of ageing thermal generation can also increase the risk to security, reliability and affordability of electricity supply, as replacement capacity may not be available to ensure resource adequacy, and electricity prices may be higher than necessary allowing existing generation to attract additional rents.

Unlike other types of commodities, there is no real substitute to power, and because it is not storable in large quantities, sufficient reserves are needed to maintain reliability. For that reason, just in time replacement is not feasible and uncertainty increases the inherent risks and costs of the system.

Correctly identifying the risks, understanding them and developing a holistic market design in response is at the centre of the ESB's market design project, and will support a transition at lowest cost to consumers.

There are a range of regulatory measures already in place in the NEM designed to respond to reliability and security risks.<sup>30</sup> In addition, the options under consideration in the Resource Adequacy Mechanisms, Two Sided Markets and Essential System Services workstreams look to further minimise the risks resulting from thermal exits. A key part of the ESB's work program will be assessing how these options fit together to ensure we are not layering multiple levels of reliability measures over one another that impose costs, for little or no benefit.

However, given the unprecedented nature of this transition, stakeholders have commented that there may be residual risks that good market design may not be able to moderate. We refer to

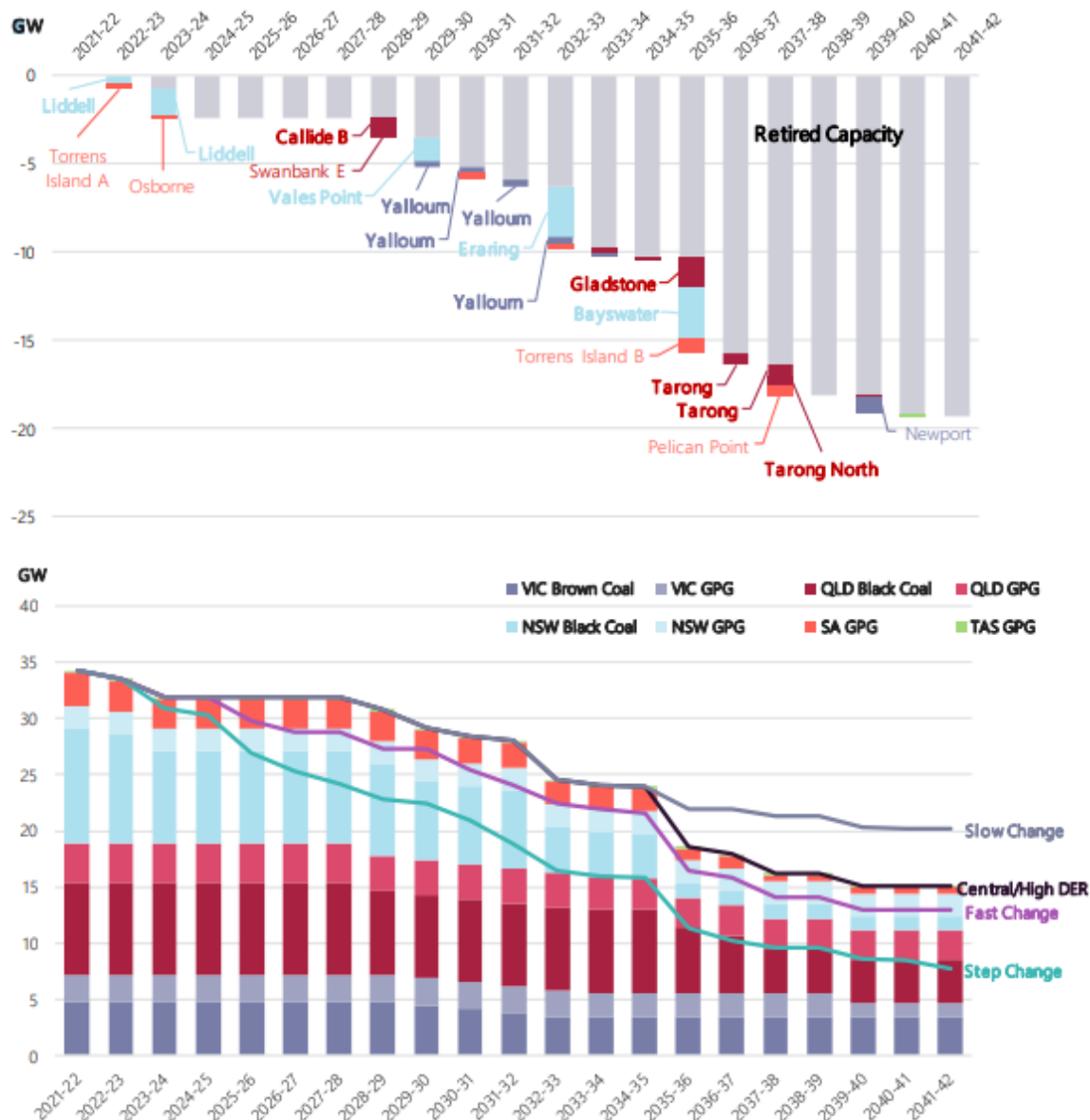
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<sup>29</sup> AEMO, ISP 2020, p12, Preface and detailed modelling notes. This amount represents the present value (2019\$) of total system costs for generation and transmission investment, as well as fuel, operating and maintenance costs using a discount rate of 5.9%.

<sup>30</sup> These measures are set out for reference on the ESB Post-2025 program website.

these as ‘residual’ risks. The aim of this workstream is not to avoid exits occurring, but rather to consider whether there are any residual risks, and seek stakeholder feedback on the existence and materiality of those risks, and possible interventions that may be considered as a result.

FIGURE 11 COAL-FIRED AND GAS-POWERED GENERATION RETIREMENTS



Note: Based on expected closure years provided by participants as of February 2020. In July 2020, CleanCo Queensland advised that the Swanbank E generator would defer its planned closure year to 2036. We do not consider this delayed retirement to materially impact the outcomes presented in the ISP.

Source: AEMO, ISP 2020

## Exits are an intended part of an efficient market response

Market participants and investors are constantly surveying the market to assess the behaviour of competing generators. The closure plans of large thermal generators can be anticipated by the market. Generators are required to notify AEMO of the expected closure year for all their scheduled generation and give at least 42 months' notice of the closure date, which is published on AEMO's website and available to the public.

Where closure is expected to result in higher wholesale or ancillary service prices or the RRO being triggered, market participants have a clear incentive to consider if new generation

investment is warranted. This is added to by the current market structure where many coal generators are owned by vertically integrated retailers and they will be incentivised to replace the capacity to supply their customers at predictable wholesale costs. This response should work somewhat to minimise the size of the increase in wholesale prices following the exit of a large thermal generator.

Even if retirement is suddenly brought forward, market signals may encourage sufficient replacement investment. Temporary high prices signal a need for investment, with investment in new types of generation and demand response being relatively quick compared to the lead times for large thermal plants in the past. There are also existing market arrangements such as RERT that can act as a backstop to provide reserves in the immediate term until new capacity is built (see Section 4.2.3).

### The risks associated with coal-fired plant exits

The level of impact following the exit of thermal generation will vary significantly by plant, the amount of notice provided, and the progress of replacement investment in, for example, generation, demand response and networks. The exit of some generators may have only mild price effects and need little market response, while others would have a major impact requiring significant investment in replacement peaking plants, demand response, batteries or synchronous services, or major network upgrades to bring supply from other areas. The specifics of the exit scenario are important to understanding the risks of exit.

A range of risks may be present when any thermal plant exits, which are discussed below. The discussion in this section focuses on coal plants, as we consider that the overall risk to the power system of exit of gas plants is lower relative to large coal plants.

The exit of ageing thermal generation can create significant uncertainties for market participants that are difficult to navigate and which risk creating significant costs to consumers. In particular, the uncertainty created by the timing of large-scale generation exit may dampen signals for investment in new replacement capacity (see RAMs Section 4). Even with mechanisms such as notice of generation closure and the use of planning documents such as the ESOO, there remain risks that large-scale generation may close at unexpected times.

This uncertainty around the timing of closure of ageing thermal generation may exacerbate the risks faced by investors in the NEM, leading to either delayed investment or increased risk of new investments, both of which may translate to higher prices for consumers. Ageing thermal generators also face uncertainty around the timing of their own closure and that of their competitors, which may lead to inefficient levels of investment in maintaining their plant, also increasing the cost of generation or leading to premature, unplanned exit (which increases the cost of maintaining the security and reliability of the NEM) (see also RAMs Section 4.1.5).

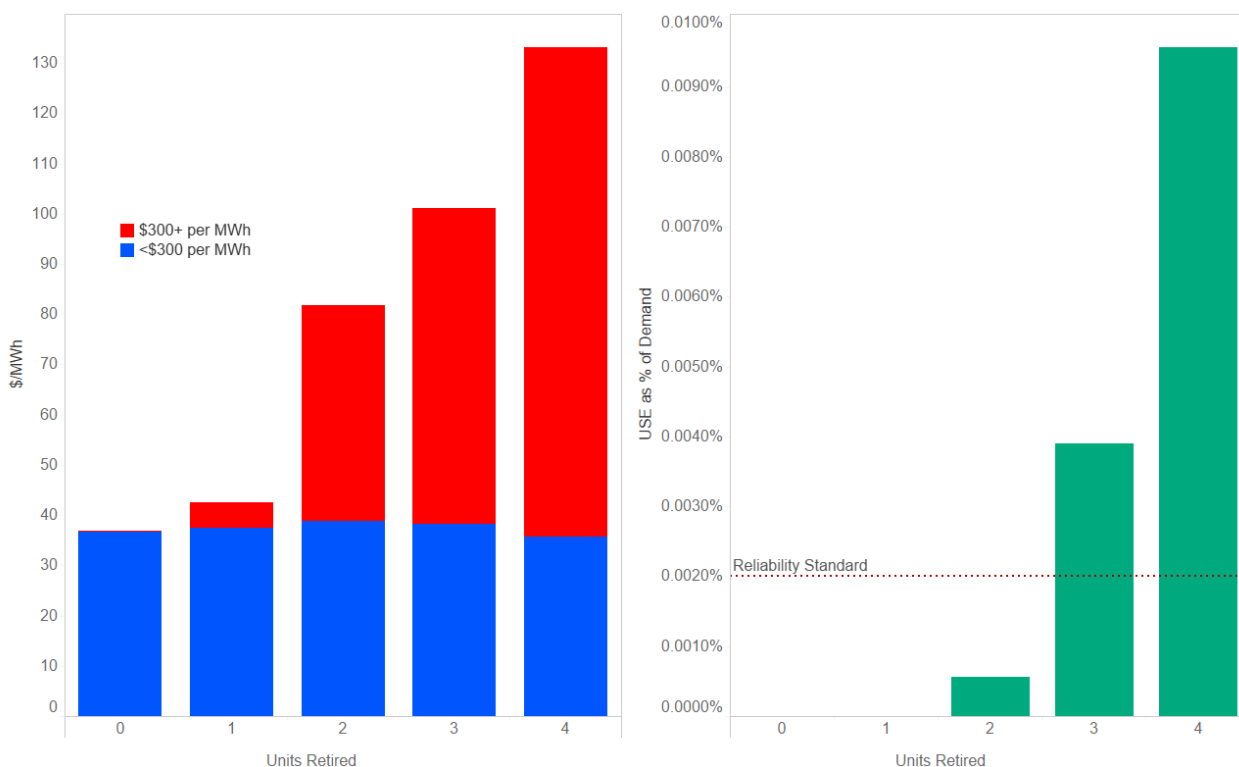
The uncertainty around the timing of closure of ageing thermal generation also creates challenges for AEMO in developing its ISP, given the nature and timing of “actionable” transmission investments will be influenced by plant exit decisions. Overall, actions taken to invest in transmission to mitigate the risk of uncertain thermal generation exit may not be required if there was greater certainty around the timing of exits. The uncertainty around the timing of closure is accentuated by the risk of a technical failure and unexpected outage, for example, that may not be repaired due to engineering or financial considerations.

A number of other factors may contribute to the timing of closure not resulting in efficient outcomes for consumers, e.g. if system services that generators provide and the power system needs are not appropriately valued and priced or, indeed, are not valued at all (the ESS MDI is seeking to address this). There may also be other barriers to efficiently building replacement generation assets, for example, within planning arrangements that sit outside the NEM regulatory framework (e.g. environmental approvals, land access or planning restrictions).



The impacts of retirements also vary depending on the amount of capacity that is closing at one time. In the stylised example shown in Figure 12, an inefficient market outcome, resulting in the Reliability Standard (0.002% unserved energy) being breached, could result from the full rather than partial withdrawal of a plant from the market. This outcome may be the best decision for the owner given their portfolio, fixed costs of the plant or, in the case of a technical failure, the make-good costs, but be an inefficient outcome for consumers.

FIGURE 12 IMPACTS ON PRICE AND RELIABILITY WITH DIFFERENT NUMBERS OF UNITS EXITING – STYLISTED EXAMPLE



Source: AEMC analysis

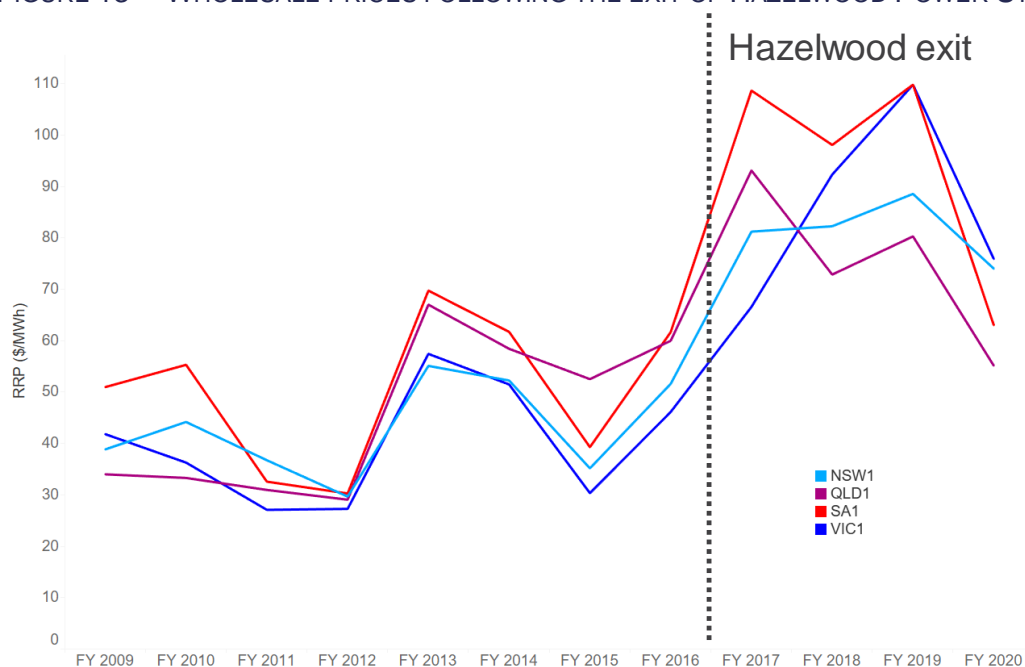
Exit of a large thermal generator at short notice can place significant upward pressure on wholesale prices. The block nature of the exit may mean that there is insufficient time for replacement generation (or demand response) to fill the gap left by the large generator leaving the market. This dynamic was observed in early 2017 when the 1600MW Hazelwood Power Station left the market with only five months' notice of closure.

Figure 13 shows the sharp increase in wholesale prices following the Hazelwood exit, particularly in Victoria and South Australia. This increase in wholesale prices occurred in the context of rising gas prices driven by LNG export demand, high electricity demand due to hot weather and increases in coal fuel costs. These factors together led to the increase in wholesale electricity prices. This experience points to the need to consider the context in which potential future exit may occur.

Following this experience, notice of closure provisions were recommended by the Finkel Review<sup>31</sup> and put in place.

<sup>31</sup> Independent Review into the Future Security of the National Electricity Market – Blueprint for the Future, <https://www.energy.gov.au/publications/independent-review-future-security-national-electricity-market-blueprint-future>

FIGURE 13 WHOLESALE PRICES FOLLOWING THE EXIT OF HAZELWOOD POWER STATION



Rising wholesale prices following a plant exit is a feature of the current market design and is not in itself inefficient. Over time, the energy only market design is self-correcting, as Figure 13 demonstrates. Tight supply conditions increase wholesale prices, which signal the need for new capacity to enter the market – this is the deliberate design of the market. Consumers are protected by the Market Price Cap and other market price limits.

### Risks from significant uncertainty in exit timing

In theory, investors respond to these wholesale price signals by building generation capacity, often in large blocks, when and where it is valued, which in turn reduces wholesale prices. This dynamic results in a ‘saw tooth’ shape of wholesale prices, leading to periods of higher and lower costs for consumers, and periods of higher and lower revenues for generators. To some extent electricity retailers manage these intense price movements on behalf of consumers and provide some smoothing of prices to consumers.

The much debated question is whether or not the price rise will be sufficient and last long enough to deliver replacement investment. Some stakeholders advise that governments are not willing to tolerate periods of high pricing that drive investment, and will instead intervene in the market. This perception, coupled with the inability to hedge large demand risk may deter future necessary investment, which in turn risks further intervention. This question of whether or not expectations of high prices are sufficient to drive investment is a key consideration of the market design initiative looking at resource adequacy (see also RAMs Section 4).

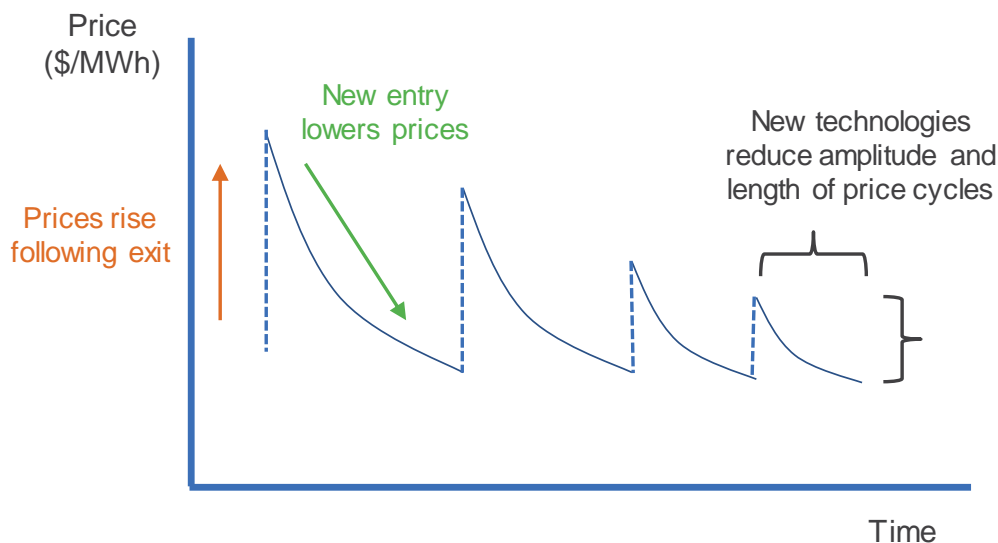
As the transition continues and thermal generators exit, it may be expected that this saw-tooth price dynamic is observed more often. As thermal plants exit there may be periods of high returns for the remaining thermal plants.

How this revenue reflects the long-run costs of the plant, future funding requirements for decommissioning costs and funding for replacement investment is something on which the ESB is interested in stakeholder views.

New peaking generation, renewable generation technologies, demand response and storage technologies tend to be more modular, and have shorter lead times than both coal-fired and gas-powered generation. This may moderate the saw-tooth effect in future, as illustrated in

Figure 14. We note that existing thermal plants currently deliver essential services for the physical operation of the power system (see Section 4 and Section 6).

FIGURE 14 NEW GENERATION AND STORAGE TECHNOLOGIES REDUCE PRICE CYCLES



Source: Adapted from Frontier Economics 2019 – NEM structure in light of technology and policy changes. A report for the AEC.

It is also possible that some ageing thermal generators will derive significant benefits from staying in the market following the exit of other ageing thermal generation. These ageing thermal generators cannot be replaced on a like for like basis but instead will be replaced (at least in the short to medium term) by higher cost and shorter duration sources of dispatchable capacity such as gas peakers, pumped hydro and batteries. The ageing thermal generators that remain in the market may be able to capture significant economic rents (excess profits) for some time as prices will need to rise to new entry levels, and at a significant premium above the costs of existing thermal generation. The ESB is interested in stakeholder views on the materiality of this issue.

Thermal generation is likely to see significant increases in operating costs, as these plants try to respond more flexibly to changes in the market or see reduced revenues during periods of high solar output. However, this increase in costs/reduction in revenues may not offset the significant increase in revenues many of these plants (particularly more efficient or lower fuel cost plants) may attract in the years following the exit of one of their competitors.

There is also a risk that exit may result in the exercise of market power by remaining market participants, which results in higher than necessary costs to consumers; for example, there may only be a small number of remaining assets able to provide energy or services at particular times.

### The financial impacts of thermal plant exit

A consideration of the financial impact of plant closure on market participants needs to include the participant's generation portfolio, its contractual positions, and its degree of vertical integration.

For example, consider two cases where an ageing thermal generator is owned by a vertically integrated retailer. Whether this participant benefits from higher wholesale prices depends on whether the participant is 'long' or 'short' generation. In the case where the participant is long generation (they have available generation in excess of their retail load), they would likely benefit from higher wholesale prices on the balance of their generation. On the other hand, a participant that is short generation (with retail load in excess of their generation) would be financially exposed to the wholesale price for the balance of their load. The situation is complicated further by the contractual positions of market participants.

Much of the analysis of spot prices should therefore be considered ‘stylised’, in that it cannot account for the financial impact, and therefore incentives, facing market participants in the event of the early closure of an ageing thermal generator.

Further, thermal exits will affect contract markets. There is risk that exits could reduce contract market liquidity, particularly when new capacity is contracted through power purchase agreements (PPAs), government schemes or new market measures.

## 5.2. What are the options for addressing these risks?

There are several regulatory measures already in place to manage some of these risks. Some of these risks are also the focus for developing appropriate market designs for Resource Adequacy Mechanisms, valuing Essential System Services and developing a two-sided market.

The ESB is considering, and asking for stakeholder feedback on whether there are residual risks that need to be considered and possibly responded to.

This section sets out:

- Current market arrangements that address some of these risks.
- How the risks might be further addressed by other Post-2025 workstreams.
- Our initial consideration of what the residual security and reliability risks could include.
- High level outlines of the types of solutions that could be usefully considered to address residual risks to security and reliability.

### Current market arrangements to address the risks

There are several regulatory measures already in place that help coordinate entry and exit of generation and minimise the risk of an inefficient outcome. These are generally aimed at providing investors greater certainty around the likely timing of exit, so a market response can be forthcoming, and at providing short term information to the system operator and other market participants so the real-time market responds to any unexpected changes. Key provisions are:

- Notice of closure requirements requiring scheduled and semi-scheduled generators to notify AEMO of the year they expect a generating unit to cease supplying electricity, and to regularly update, with the obligation being to provide the market at least 42 months’ notice.
- The RRO, which encourages contracting, reducing uncertainty for existing assets.
- The ISP, which reduces uncertainty on future network capacity.
- The ESOO, which provides a 10-year forecast of whether the reliability standard will be met, giving the market time to respond to forecast gaps in meeting the Reliability Standard.
- Arrangements to provide publicly available information about new grid-scale generation projects.<sup>32</sup>
- A range of medium and short term assessments of resource adequacy, which can help to identify medium and short term impacts of closure or lack of availability, allowing other resources to respond as necessary.
- Backstop mechanisms such as the RERT and AEMO interventions in the event of unexpected, short notice exit or availability.

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<sup>32</sup> AEMC, Transparency of New Projects, Rule determination, 24 October 2019

We also note the role of the market signals, the contract markets and the vertically integrated market structure in providing incentives to manage risks related to thermal exit.

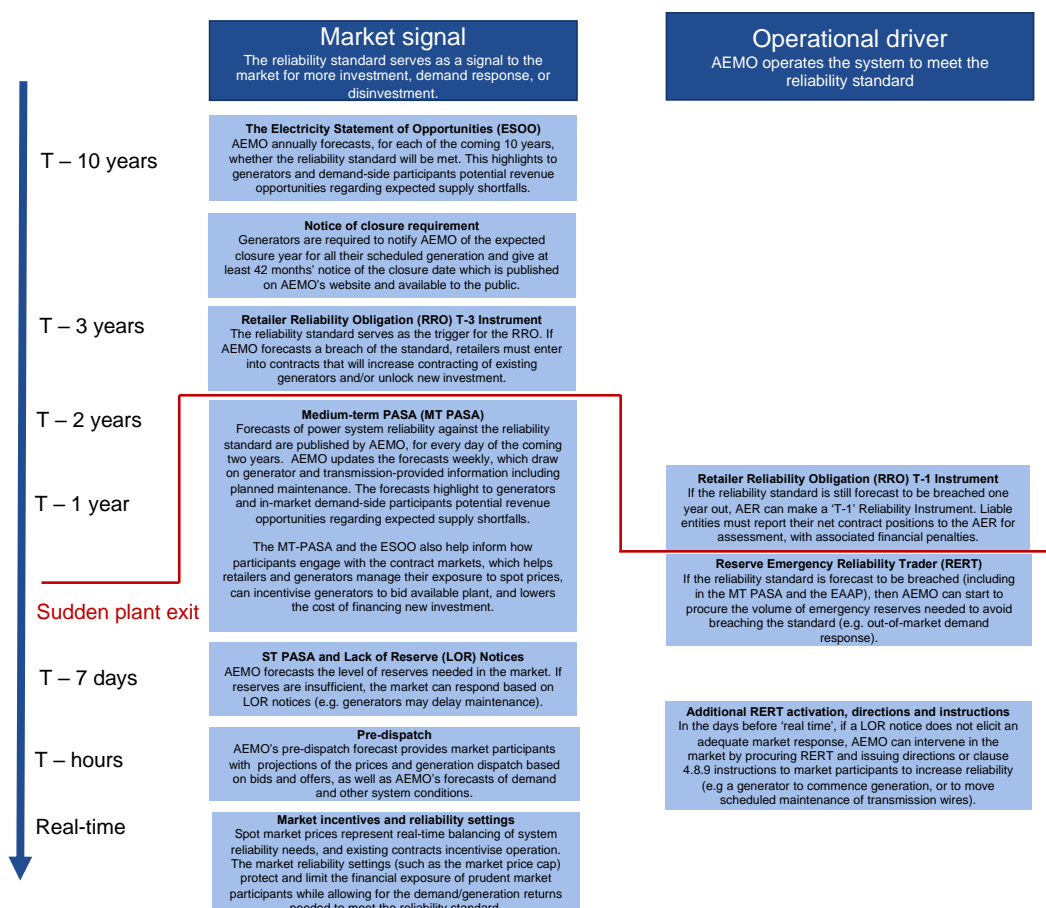
There is also the possibility of sudden or unexpected exits. In NEM regions where there is a tight supply demand balance (South Australia, Victoria and New South Wales), peak demand typically occurs in the summer months. In a sudden exit scenario, only the short-term reliability measures (less than one year) will be available to address a reliability shortfall. This creates increased pressure on prices for consumers.

A timeline of the existing reliability measures for the sudden exit scenario is summarised in Figure 15. The red line demarcates which market signals and operational drivers may assist in addressing a reliability shortfall in a sudden closure scenario. These measures are therefore primarily short term measures and are not intended as a substitute for longer term investment in capacity.

Further, the longer term measures outlined above and in Figure 15 that are intended to coordinate entry and exit may not adequately address the uncertainties over the timing of generation closure and its impacts on investment incentives in the wholesale market.

For more information regarding these mechanisms, see the ESB Post-2025 program website.

FIGURE 15 RELEVANT RELIABILITY MEASURES IN THE SUDDEN EXIT SCENARIO



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In addition to the current arrangements, there are several rule changes under consideration and other Post-2025 work streams that will consider whether the NEM needs to be improved to managed coal-fired plant exits.

The following MDIs look to provide reliable and secure electricity generation at the lowest cost to consumers in response to thermal exits; valuing those services that are critical to the reliability and security of the system should help minimise the risk and impact of inefficient exit:

- Market Design Initiative A – Resource adequacy mechanisms.
  - The RAMs MDI is assessing whether additional mechanisms are required to ensure reliability can be maintained at the lowest cost to consumers. Any new mechanisms could improve coordination of entry and exit of generation and reduce the risks associated with exit. It could sharpen incentives for timely investment in new capacity to enter the market and thereby mitigate the consumer price risks associated with sharp price fluctuations.
- Market Design Initiative C – Essential system services.
  - The assessment of whether essential system services are properly valued in the market will help ensure critical security is maintained as the thermal generators exit. This will proactively create markets for services and help to minimise the cost impacts associated with procuring these services when thermal generators leave the market. Proactively creating these markets provides additional revenue streams for new investments with the right characteristics and should minimise the risk of needing to procure these services at the last minute, when thermal generators leave.
  - The AEMC has also received seven rule change requests that seek to better allow for the provision of services that are essential for maintaining the power system in a secure operating state and delivering a reliable supply to electricity consumers.<sup>33</sup> These rule changes are collectively referred to as the ‘system services rule changes’. They are being assessed in close coordination with the ESB including how they relate to the market design initiative dealing with ESS.
- Market Design Initiative E – Two-sided markets.
  - Arrangements to facilitate a greater participation of demand side resources could be particularly valuable in facilitating a response to unexpected exit. For example, an active demand side could compete with supply side resources in meeting reliability, security and affordability challenges in the event of a large plant exit. This would reduce the need for additional supply side capacity to ‘fill the gap’ left by the exiting plant, and keep prices as low as possible for consumers.

### Initial consideration of residual risks

Table 4 below sets out our initial analysis of the residual risks that remain after considering the effectiveness of current measures and the role of possible further measures under consideration. The key residual risks for further analysis could include:

- Insufficient notice or lack of compliance with notice of closure requirements.
- Uncertainty surrounding large blocks of capacity retirements that are ‘unmanageable’ by the market, which may impede new investment signals and which create significant challenges for AEMO as transmission system planner.
- Unexpected and sudden technical failures, which, in particular, could lead to retirement of the entire plant.
- The risk of economic rents accruing to thermal generation that remains in the market following the exit of other ageing thermal plant.

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<sup>33</sup> See the AEMC’s consultation paper on the *System services rule changes*, July 2020.

TABLE 4 INITIAL CONSIDERATION OF RESIDUAL RISKS

Risk of inefficient outcomes	Current control measures	Residual risks to consider under MDI-B
Insufficient notice for new assets to be made available	Notice of closure ESOO, ISP, EAAP, PASA for planning RERT, directions and instructions for avoiding short term impacts Interim reliability measures	Insufficient notice or lack of compliance with notice of closure requirements Mothballing at short notice
Uncertainty surrounding the timing of large blocks of capacity retirements	Notice of closure ESOO, ISP, EAAP, PASA for planning RERT, directions, instructions for avoiding short term impacts Interim reliability measures	Uncertainty surrounding large blocks of capacity retirements with price, reliability and security impacts
Sudden plant failure or exit (less than a year)	Notice of closure ESOO, ISP, EAAP, PASA for planning RERT, directions and instructions for avoiding short term impacts	Sudden plant closures are too large for current arrangements to manage, resulting in price, reliability and/or security impacts
Subject to input and further consideration on the extent of economic rents accruing to coal-fired generators that remain following the exit of other coal-fired plants	Open access market to encourage competition	Depending on analysis, risks of remaining coal-fired plant accruing economic rents, above long-run marginal costs, for a period while replacement dispatchable generation is more expensive  This is not a market conduct issue

### What options are proposed for further consideration and development?

Following further analysis and input from stakeholders, if the ESB forms the view that there are residual security and reliability risks that may be addressed by regulatory change, then options will be investigated.

For example, to address the risk that there is insufficient notice of exits of ageing thermal generators and a lack of certainty around the possible timing to enable replacement assets to be made available, a number of approaches have been used internationally and raised by stakeholders:

- Reconsideration of the provisions and penalty around the Notice of Closure requirements. The Grattan Institute has also suggested enhancing notice of closure requirements by requiring coal plants to nominate their own closure windows and make ongoing payments to AEMO which are held against compliance with the window. This seeks to strengthen certainty (compared to notice of closure provisions) around the timing of retirement and thus foster a timely market response, reducing consumer costs and risks to reliability and security. The payments held against compliance provide a natural incentive for compliance and funds to compensate consumer for non-compliance.<sup>34</sup>

<sup>34</sup> Wood, T., Dundas, G., and Percival, L. (2019). *Power play*. Grattan Institute.



- Regulated or negotiated arrangements with thermal plants. This could include contracts made between generators and AEMO, such as Reliability Must Run<sup>35</sup> arrangements as in the US, or contracts made between generators and governments.
- Contingent scenario planning, whereby jurisdictions undertake some planning for unexpected events.

### 5.3. What are we proposing to do next?

Following stakeholder feedback, we will finalise the ESB's view on whether there are significant residual risks relating to ageing thermal generators exiting and if additional measures are needed to address these.

If so, these will be developed by mid-2021, in consultation with stakeholders.

By mid-2021, we aim to develop a holistic market design that sets out how existing arrangements and new mechanisms will be utilised to enable the transition away from ageing thermal generation to meet the long-term interests of consumers.

### 5.4. Questions for stakeholders

1. Have we correctly identified the cost, reliability and security risks to consumers from the transition away from thermal generation?
2. Are these risks likely to be material, particularly those relating to consumer costs?
3. Are there additional or alternate market design approaches that will ensure the transition away from thermal generation is least cost to consumers?
4. Should the ESB consider and develop any of the options outlined in this section further?

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<sup>35</sup> Under this arrangement, plants that are likely to exit and which are critical are directed to continue operating for reliability and/or security purposes. Once a reliability assessment has been completed, these resources would individually contract with the system operator and receive a regulated return, similar to networks, for the reliability service they provide.

## 6. ESSENTIAL SYSTEM SERVICES – MARKET DESIGN INITIATIVE C

### Key points

This initiative develops a reform path for essential system security services that maps current and future required reforms to maintain the NEM in a secure, resilient state as it transitions to a low emissions future.

The changing mix of resources on the grid means that certain capabilities delivered as a by-product of energy by thermal generators, now need to be delivered by other means to keep the system secure and reliable. These essential services include inertia (physical or synthetic), system strength, provision of reserves, and fast responding frequency control services. In the absence of markets to procure these services (in particular, inertia and system strength), as system operator, AEMO needs to intervene in the market, resulting in less efficient outcomes, inefficient investment signals, more complex operational decisions and higher costs to consumers.

The ESB is exploring a spectrum of options to deliver the necessary services in a timely fashion, ensuring that the grid continues to be secure and reliable as the system changes, and minimise delays and barriers to entry for new generation. The ESB has a preference to move towards real-time markets for services where the system and technologies allow, as this will deliver the clearest price signals. However, some services (particularly system strength) appear better suited to structured procurement arrangements, such as TNSP provision, bilateral contracts between AEMO or NSPs and providers, and generator access standards or mandatory technical limits. Other options set out for discussion and further development include:

- Development of a co-optimised spot-market for inertia, intended for longer term implementation.
- Development of operating reserves, also being considered in the Resource Adequacy Mechanisms workstream, which could support operational decisions and improve reliability.
- Exploration of how to incentivise primary frequency response in the NEM ahead of the mandatory primary frequency response sunset in 2023, and options for procuring and co-optimising faster frequency response.

The ESB is seeking feedback on the procurement options being considered, and the benefits, costs, and risks of procuring services ahead of time versus through real-time spot markets.

### 6.1. What is the problem this initiative is addressing?

The NEM has traditionally relied on thermal generators to provide the frequency control, inertia and system strength required to ensure system security. Because inertia and system strength were historically provided as a by-product of energy generation, the NEM has not had mechanisms to signal the need for, or pay for, these services until recently. With the current proportion of non-synchronous generation in the NEM, those services can be short of requirements at times and AEMO has needed to intervene in the market to maintain security. The problem was highlighted as critical in the ESB's Health of the NEM report<sup>36</sup>.

This issue is becoming more prevalent as the generation mix continues to change, and the challenge will keep growing unless action is taken to modify and expand the current ancillary

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<sup>36</sup> ESB Health of the NEM: <http://www.coagenergycouncil.gov.au/publications/health-national-electricity-market-0>

services regulation and procurement processes to enable all essential system services necessary to support the grid. The drivers for this change are outlined in detail in Section 2.

The current arrangements are not providing adequate signals for efficient operational scheduling to provide all the services the power system requires, nor for investors to respond to these needs. Intervention by AEMO is a necessary but inefficient measure that increases costs to consumers without providing a market incentive for participants to invest in new plant or adaptations of existing plant.

Without changes, the market is likely to see:

- More interventions to maintain system security (there has been a 10-fold increase from less than 20 directions in 2015-16 to more than 200 in 2019-20), with increased costs to consumers.
- Poor frequency control, potentially breaching standards and making the system less resilient to disturbances.
- Greater complexity in operations and planning resulting in inefficient outcomes.
- Increased risk of cascading failures leading to load shedding.

In response, a number of changes to the market have been made or are in train. In September 2017, the AEMC made changes to the market arrangements to make TNSPs responsible for maintaining minimum levels of system strength and inertia once AEMO declares a shortfall and for new generators connecting to the grid to 'do no harm' to system strength<sup>37</sup>. The AEMC is undertaking further work in this area including assessing several additional proposed rule changes<sup>38</sup>.

In March 2020, the AEMC made new rules requiring all scheduled and semi-scheduled generators in the NEM to provide primary frequency response; that is, to support the secure operation of the power system by responding automatically to changes in power system frequency. These provisions were designed to address the immediate need to improve frequency control but sunset after three years, by which time enduring arrangements that incentivise the provision of frequency response are expected to be implemented.

The ESB's comprehensive System Security Workplan, published in March 2020<sup>39</sup>, outlines key short-term initiatives.

## 6.2. What are the options considered?

### The approach

A conceptual framework categorises the options for procuring services (Figure 16):

1. 'Directions and self-provision of services' without market-based remuneration.
2. 'Structured procurement' via non-spot-market mechanisms.
3. 'Spot market-based' provision of services, including potential contracts-for-difference relative to real-time prices.

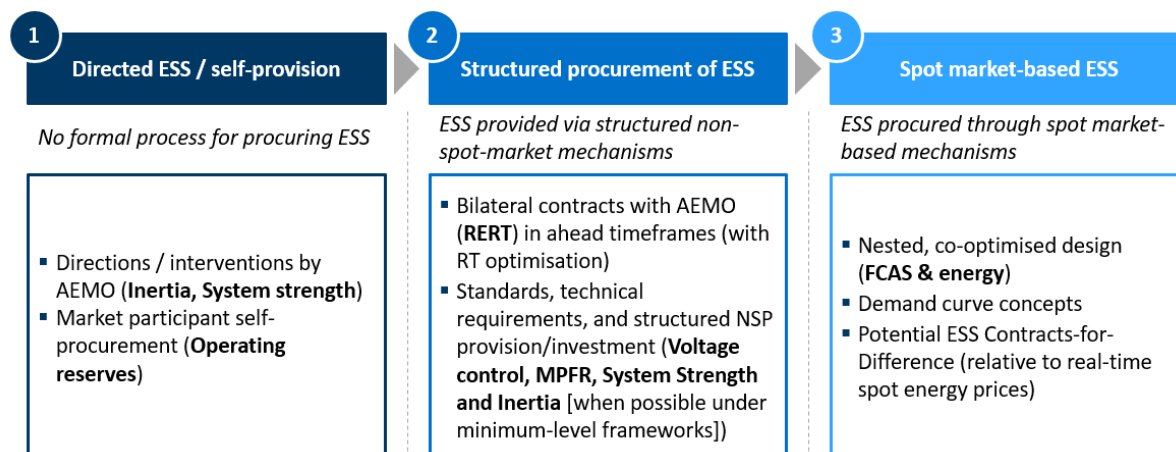
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<sup>37</sup> AEMC Managing Power System Fault Levels Rule (2017) <https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels>

<sup>38</sup> AEMC System Services Rule Changes Consultation Process (2020) <https://www.aemc.gov.au/news-centre/media-releases/consultation-begins-new-ways-deliver-system-services-power-system>

<sup>39</sup> ESB System Security Workplan: <http://www.coagenergycouncil.gov.au/interim-security-measures>

FIGURE 16 PROCUREMENT OPTIONS FOR ESSENTIAL SYSTEM SERVICES (WITH IDENTIFICATION OF CURRENT PROVISION MECHANISMS FOR SERVICES IN BOLD)



Source: FTI, Essential System Services Report, Chapter 6.

Within this framework we considered procurement options for operating reserve, frequency control, inertia and system strength.

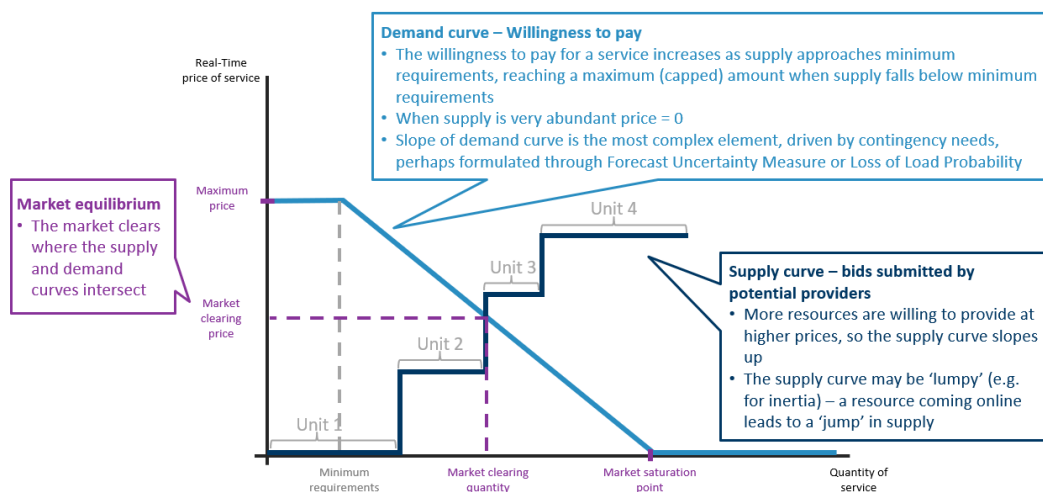
- Option 1 – directed ESS/self-provision.
  - This is to incentivise or require procurement by market participants in their operating arrangements and the use of directions and intervention by AEMO when pre-dispatch shows the lack of an ESS. Participants currently offer operating reserves to the market to manage price risks and AEMO monitors their availability, issuing Lack of Reserve notices and intervening if there is a shortfall. There is effective procurement of minimum levels of inertia and system strength through TNSPs in some NEM regions. Interventions have been relied on where TNSP contracting has proved to be less viable. While Option 1 has disadvantages, the need to maintain security across all operational circumstances and in a changing power system means it is important that this remains in all options, at least as a backstop.
- Option 2 – structured procurement.
  - This seeks to put a more structured approach to procurement of ESS, valuing services through one of a number of potential mechanisms. There are existing examples of structured procurement, including:
    - Procurement by AEMO of system restart services and RERT.
    - Provision of minimum levels of system strength and inertia by TNSPs.
  - A number of key services are not explicitly valued in the current framework on an ongoing basis (e.g. operating reserves, inertia, system strength). By not valuing these services, or only valuing them when a shortfall has been declared, there is no clear investment signal. In some cases, this approach can lead to a lack of transparency, ad-hoc procurement and high costs. A structured procurement could be applied, for example, to procure inertia and system strength resources through a combination of medium to longer term contracts and short term auctions from synchronous service providers, as well as through the provision of network services.
  - A combination of complementary procurement options may lead to the least cost of delivery, and it is important that arrangements do not introduce a bias between the use of existing assets, investing in new assets and between competitive procurement and network procurement.

- Bilateral and financial contracting approaches might foster greater incentives for investment than short term auctions alone. Short term auctions to procure contracts, may, however, sit alongside longer duration bilateral contracts. *Bilateral contracts* may be struck between TNSPs or AEMO and a service provider for the delivery of a required service. It is a relatively simple approach to procurement, and is commonly employed and familiar to both AEMO and TNSPs. Bilateral contracting may be established without (or before) a spot market is introduced, providing an opportunity to procure and price services, relatively quickly, before developing the detailed design required of a spot-market approach.
- A drawback of bilateral contracting without spot markets is that physical performance is required, with no way for a service provider to financially settle a deviation from their contract. In the presence of low energy prices, providers that must generate energy to supply the system service may be reluctant to enter into long term contracts if they may incur a loss in the energy market when called on to provide the service. The bilateral contract could be structured as a contract-for-difference against the energy spot price to mitigate this risk of loss to the service provider. To effectively address this issue in the long term, the provision of system services should transition to being accompanied by no or very low energy resources.
- For existing synchronous generators, this would require investment to support an ability to operate in synchronous condenser mode or to reduce their minimum generation. Long term contracts for these services may help drive investment from new energy service providers rather than relying solely on ageing thermal generation facilities.
- If the procurement framework for services transitions to include a spot market, contracting may be via a financial structure, as discussed in the next section. Bilateral contracting may also support the trialling of new services and/or new technologies.
- *Short term auctions* could be used to procure bilateral and financial contracts and include resources that are not otherwise contracted. The advantage for the service provider is that they have better knowledge of the state of their plant and costs in the short term than many months or years ahead. By extending the pool of resources that can supply the service, the costs of provision can be minimised.
- *Financial contracts* can provide options to support investment against spot-market prices, such as the central procurement (e.g. by AEMO) of option contracts from providers of system services. Under these forward contracts, an option payment would be paid to the system service provider throughout the term of the contract; in return, the provider would pay back difference payments during times of high spot prices. The contract would be held centrally and would hedge consumers against the cost of services procured through the spot market.
- An auction to procure the system service option contracts could be run periodically, with contracts awarded to providers with the lowest offer price. Demand curves could be developed for forward periods alongside those prepared for the spot market, providing regulatory oversight and transparency of requirements over the investment horizon. Auctions for each system service could be run simultaneously, allowing resources capable of providing multiple services to participate in each, enabling the minimisation of costs.
- Option 3 – Spot market-based procurement.
  - This is the use of spot markets to procure ESS. This approach, where practicable, allows full co-optimisation between services and between services and energy. This could provide both more efficient dispatch and pricing of services, and potentially drive innovation in the provision of various combinations of ESS from different technologies

including DER. Frequency control ancillary services (FCAS) are currently procured through co-optimised spot markets. Option 3 could extend to incorporate the demand curves for some services rather than a fixed demand requirement, purchasing services in a manner which maximises the value of the services provided.

- A “demand curve” expresses the relationship between the demand for a service or commodity and its price, effectively expressing the value of a quantity of a service from the perspective of the buyer. Currently, ancillary service spot markets in the NEM set a fixed level of demand for that service irrespective of the price.
- The key advantage of a demand curve approach is that it maximises the value of procurement, setting a minimum requirement when the price is high and procuring more of a service when efficient to do so. This can be a particularly valuable concept in the future procurement of some system services, given the spot market price varies over five orders of magnitude and that, in a market with more variable resources, it is no longer sufficient to set volumes against a clearly defined single credible event. Higher reserves and contingent FCAS have resiliency benefits in allowing the market to cover a greater set of potential contingency events. With a demand curve appropriately set to value the benefit of these higher reserves, the market will be more resilient when the costs are justified.
- Demand curves additionally support investability by valuing the provision of resources beyond minimum requirements, although this requires deriving an appropriate cost-benefit curve. This is particularly important where supply is ‘lumpy’ – for example, the provision of inertia by synchronous generators.

FIGURE 17 AN ILLUSTRATIVE DEMAND CURVE FOR AN ESSENTIAL SYSTEM SERVICE



Source: FTI

- The shape of a demand curve must, however, be derived outside of the market, delivering an appropriate cost-benefit trade-off. This could involve the Loss of Load Probability and the value of customer reliability for different levels of reserves, and potentially the Forecast Uncertainty Measure for the NEM. Demand curves can also be utilised in centrally-optimised unit commitment decisions using mixed integer programming.

## Operating reserves





An operating reserve is dispatchable capacity that is available to respond to unexpected changes in demand or supply, including the ability of the system to meet peak demand and ramp events over a number of dispatch intervals. Operating reserves, measured in MW, may be provided by




either generation or demand response capacity and may be online and spinning or offline, as long as it can be made available within required timeframes. Operating reserves can include DER, subject to appropriate compliance mechanisms.

The forecast increase in uncertainty and variability of net demand ramps<sup>40</sup> suggests additional reserve mechanisms will be needed for the NEM in the near to medium term. On the other hand, the availability of conventional generators to supply those reserves will decline and decline rapidly in some time periods. The provision of future reserves will likely be increasingly provided by alternative resources including pumped hydro storage, battery storage and demand response, including utility scale and distributed resources.

Section 4 considered the role of operating reserves in long term resource adequacy; in this section, they are considered in the context of short term adequacy, including managing uncertainty and variability. There is currently no centralised mechanism for the procurement of operating reserves; rather, they are implicitly provided as a consequence of the energy market decisions of individual suppliers seeking to manage their risks. Figure 18 shows FTI's assessment of the case for an operating reserve.

FIGURE 18 INITIAL ASSESSMENT OF MARKET DESIGN CHARACTERISTICS OF OPERATING RESERVES

<b>Definition and measurability</b>	A reserves service can be objectively defined, measured (in MW) and monitored	
<b>Scope for competition</b>	Good scope for competition (wide range of providers, spatial need mostly at region level, typically with relatively limited market power concerns/risks)	
<b>International experience</b>	Numerous international examples for the procurement of reserve products	
<b>Scope for co-optimisation</b>	Good potential for co-optimisation with other ESS and bulk energy, subject to RAMs and locational design (e.g. both energy and reserves to be procured at the same geographic level)	

**Legend**  Highly favourable to spot market-based ESS  Somewhat favourable to spot market-based ESS  Not favourable to spot market-based ESS

Source: FTI

FTI characterises the range of options for the future provision of operating reserves as spanning the following:

- Directed ESS/self-provision – little change from status quo, potential for more formal identification of the levels of operating reserve available in the ahead timeframe, but not explicitly valued/remunerated.
- Structured procurement – possibilities to procure operating reserves through non-spot-market mechanism, for example, via contracts similar to RERT.
- Demand curve spot market – spot market-based procurement and scheduling where price is determined by the intersection of formulated demand curves and provider supply curves.

The ESB proposes to further consider options for an operating reserve mechanism or operating reserve demand curve spot market. The AEMC is considering a rule change on operating

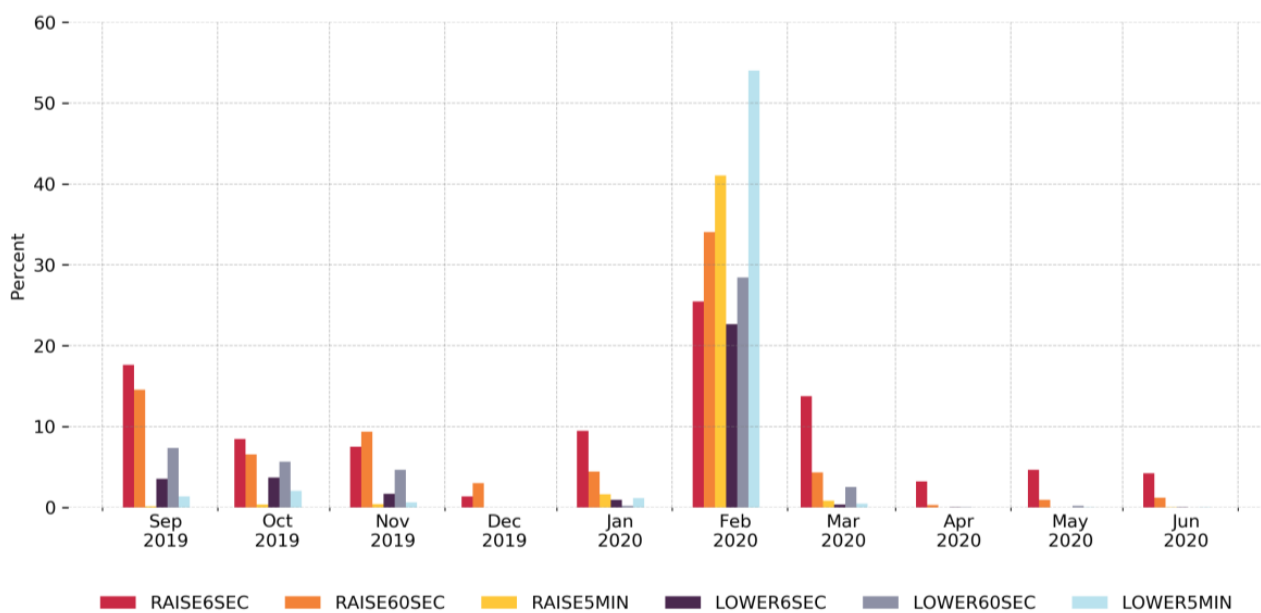
<sup>40</sup> AEMO Renewables Integration Study 2020



reserves. A minimum level of operating reserves (which could vary at different times according to system conditions) could be defined, which would be needed under all circumstances to manage volatility in supply and demand. However, there could be value in purchasing greater than this minimum level if the price of those reserves is low.

For example, Figure 19 shows historical Contingency FCAS prices, which are very fast acting reserves. While the prices were very high in February 2020 because of the islanding of South Australia, reserves are typically available at low cost (less than \$25/MWh). Purchasing additional operating reserves at low-price times (e.g. through a demand curve) could deliver additional reliability and security at relatively low cost. In a recent report to the Australian Renewable Energy Agency (ARENA), AEMO provided information on the profile of costs of FCAS in South Australia and the performance of DER in VPP trials to provide those services.<sup>41</sup>

**FIGURE 19** PERCENTAGE OF DISPATCH INTERVALS DURING WHICH CONTINGENCY FCAS PRICES EXCEEDED \$25/MWh, SEPTEMBER 2019 TO JUNE 2020



In developing this option, several design characteristics will need to be established:

- Define the characteristics of system events that Operating Reserve will help to address e.g. reliability, security or both.
- Define the regionality of requirements.
- Define the products and frameworks that may support these requirements (including timescales of provision, regional characteristics, call times), noting interactions with the Scheduling and Ahead Mechanisms MDI-D.
- Identify frameworks to set minimum and additional levels of provision where it is efficient to do so.
- Identify opportunities for co-optimisation, possibly nested, across different products.

## Frequency control

Frequency control mechanisms act to stabilise power system frequency by varying active power in response to frequency variations. Mechanisms can be centrally managed through the energy

<sup>41</sup> AEMO Virtual Power Plant Demonstrations, July 2020, Knowledge sharing report No. 2

management system or can respond to local changes in frequency. The response can be triggered as an on or off service or can be proportionate to the frequency divergence.

Frequency performance has recently declined in the NEM for a number of reasons, explored in detail in AEMO's Renewable Integration Study (2020) and AEMC's Frequency Control Frameworks Review (2018). In the past, frequency control services have been procured in the NEM through co-optimised spot markets. Narrow deadband primary frequency control services had been supplied voluntarily through the governors on conventional generators. Regulating services in the NEM respond to central dispatch signals and operate more slowly as a result. As noted earlier, the AEMC made new rules in March 2020 requiring all scheduled and semi-scheduled generators in the NEM to provide a primary frequency response; that is, to support the secure operation of the power system by responding automatically to changes in power system frequency to the extent they are able. These provisions are interim and will sunset after three years to allow time for a more enduring framework that incentivises the provision of this service to be developed.

AEMO is also working with Standards Australia on an update to the inverter technical standard 4777.2 to improve voltage and frequency disturbance ride through of IBR, maximising the frequency performance and value of DER. The ESB is proposing a rule change to put in place a DER Standards Governance Committee to set and update DER technical standards in a subsidiary instrument under the National Electricity Rules (Rules). These changes should minimise any need for additional DER device related frequency control.

The changes in the power system will progressively increase the need for frequency control services and reduce access to conventional suppliers of these services. The AEMC is progressing its frequency control work plan, which coordinates actions by the AEMC, ESB, the AER and AEMO to support the stable and secure operation of the power system in relation to frequency control. Currently two proposed rule changes are being assessed which seek to refine the current arrangements.<sup>42</sup>





The ESB proposes to develop a range of options for frequency control, which coordinates closely with the work of the AEMC. Options under consideration include:




1. Reviewing the need to modify current services or introduce additional frequency control services to effectively manage frequency in the future power system. The new services under consideration by the AEMC include a fast frequency response co-optimised with inertia and other standard regulating response.
2. Potential co-optimisation of FCAS services with other essential system services including any proposed inertia and operating reserve services.
3. Exploring improvements to investability, including options to have AEMO purchase forward contracts for differences on key frequency control services.
4. Exploring options to define demand curves for frequency control, allowing the valuation of the provision of frequency response beyond minimum levels to support greater resilience
5. Closely observing and learning from the implementation of Western Australia's Market Reform program, in particular the introduction of the rate of change of frequency (RoCoF) Control Service and its co-optimisation with Contingency FCAS.

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<sup>42</sup> AEMO Primary Frequency Incentive rule change request (<https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements>) and Infigen Fast Frequency Response rule change request (<https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service>) are the two change requests related to frequency control.

FIGURE 20 INITIAL ASSESSMENT OF THE MARKET DESIGN CHARACTERISTICS OF FREQUENCY CONTROL

<b>Definition and measurability</b>	A frequency response service can be objectively defined, measured (in MW) and monitored	
<b>Scope for competition</b>	Good scope for competition (wide range of providers, spatial need mostly at region level, typically with relatively limited market power concerns/risks)	
<b>International experience</b>	Numerous international examples for the procurement of frequency response products	
<b>Scope for co-optimisation</b>	Already co-optimised with bulk energy and high potential for co-optimisation with other ESS (e.g. reserves)	

**Legend**  Highly favourable to spot market-based ESS  Somewhat favourable to spot market-based ESS  Not favourable to spot market-based ESS

Source: FTI

### Provision of inertia

Inertia is the store of kinetic energy that is “provided by the aggregate rotating mass of all synchronous machines and motors that are directly coupled to the grid”,<sup>43</sup> reducing the rate at which frequency changes following a disturbance, and hence increasing the resilience of the power system to disturbances.





Inertia is provided in the NEM mainly as a “by-product” of bulk energy or through synchronous resources. As IBR in the NEM grow and synchronous generators retire, there could be an increasing number of dispatch intervals where there will be insufficient inertia available to the system unless action is taken. In these circumstances, inertia could be provided by:




- Operating synchronous generators out of merit order.
- Additional conventional resources of inertia from synchronous condensers or synchronous generators adapted to run in syncon mode, including the potential additions of fly wheels.
- Potentially new technologies producing forms of “synthetic” or “virtual” inertia. While such technology is under active development and two battery storage installations in the NEM are being trialled, the extent to which these technologies can deliver the system requirements and replace or supplement synchronous inertia is unknown.

The need then is for arrangements which drive investment and dispatch of the optimal mix of possible supplies, and which support innovation. Inertia is quantifiable, with a clear unambiguous metric, allowing a possibility that it may be suited at some point in the future to a real-time spot market-based procurement mechanism, noting that there are limited examples of real-time markets for inertia, with the Western Australian Electricity Market reforms perhaps providing the most advanced demonstration of such a service (RoCoF Control Service).

<sup>43</sup> AEMO Renewable Integration Study 2020

FIGURE 21 INITIAL ASSESSMENT OF THE MARKET DESIGN CHARACTERISTICS OF INERTIA

<b>Definition and measurability</b>	An inertia service can be objectively defined, measured (in MWs) and monitored	
<b>Scope for competition</b>	Uncertain scope for competition across locational needs (narrowing range of providers driven by the displacement of thermal, synchronous generators, with some locational requirements e.g. specific states)	
<b>International experience</b>	Limited international precedent for the procurement of inertia services, although there is emerging experience from WEM. Also very similar to RT pricing of spinning reserves in NYISO.	
<b>Scope for co-optimisation</b>	Inertia is provided by resources being online. Unit commitment needs to be co-optimised.	<div>Forward procurement</div>  <div>Demand curves</div>

**Legend**  Highly favourable to spot market-based ESS  Somewhat favourable to spot market-based ESS  Not favourable to spot market-based ESS

Source: FTI

There is also the potential to use alternative procurement approaches, including contracting by AEMO or regulated procurement through TNSPs. The Rules provide an obligation for TNSPs to supply a minimum level of inertia when AEMO identifies a shortfall. These provisions have been used to procure four synchronous condensers for the South Australian region with flywheels for inertia.

Following the procurement of minimum requirements, additional needs for inertia may occur under certain operating conditions. Under the current arrangements, AEMO would have to intervene in these cases and direct synchronous generators to operate out of merit order. Compensation payments are payable in these circumstances. The use of directions should only be a fallback, as the compensation payments made do not drive efficiencies or investment.

The provision of inertia could be valued and procured through a mix of longer term regulated procurement of specific resources and both short and long term contracting for additional inertia. The mix chosen should be informed by the relative cost of the alternatives, opportunities for innovation, and competition. In the short term, the contracting would need to be structured to reflect the supply cost characteristics and energy prices. There are proposed rule changes which aim to address the provision of inertia being assessed through the AEMC Rule Change Process, notably *synchronous services markets* and *fast frequency response ancillary service markets*.

An additional proposal into this process from ERM and CS Energy seeks to combine inertia and other services into a combined “synchronous services” product. When the projected supply of synchronous services is inadequate, AEMO could run a competitive auction to elicit bids from resources to provide synchronous services instead of directing plant. (This approach, known as Power System Security Ancillary Services (PSSAS) was proposed by ERM and CS Energy during stakeholder consultations). This presents one option considered by FTI as an example of structured procurement.

The provision of inertia from synchronous generators is dependent upon the plant being committed and synchronised to the power system ahead of the requirement. A structured procurement approach will need to consider how such plant operating under either contracts or supplementary auctions could be efficiently scheduled (see Section 7).

In the intermediate to longer term, the ESB aims to move to a demand curve spot market-based procurement mechanism. Spot market procurement would allow co-optimisation with the provision of energy but also of other related system services including frequency response and

operating reserves, noting that different technologies could provide a different mix of solutions. It would also explicitly recognise the value of additional inertia above the minimum, which could improve security and allow higher dispatch of low cost generation. Potentially, a contract for difference mechanism around a possible real-time price could be offered to provide a longer term investment signal and incentives for operation and plant commitment. This would require additional governance arrangements, including procurement guidelines and transparency requirements to ensure value for money.

### Provision of system strength

System strength is an emerging concept for power systems globally, and can perhaps best be defined as “the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance” (AEMO Renewable Integration Study 2020).

Historically, system strength was not an explicitly procured system service in the NEM. Rather, it was provided as a by-product of synchronous machines, including synchronous generators and synchronous condensers. In 2017, new rules were made that require TNSPs to supply a minimum level of system strength when AEMO identifies a shortfall. These provisions have been used to procure four synchronous condensers for the South Australian region, which meet both inertia and system strength gaps. The arrangements also require parties connecting to the grid to be able to operate and meet their technical standards in a system with low system strength and to not degrade system strength. These arrangements are currently being reviewed by the AEMC<sup>44</sup>, including through a review of the system strength framework and the assessment of rule change requests.

While the current arrangements aim to deliver a minimum level of system strength, there will be occasions where additional system strength services are required to securely operate the power system. Under the current arrangements, AEMO would need to intervene and direct synchronous plant to operate out of merit order to deliver these services. The power to direct is, again, important as a backstop, but is expensive and does not incentivise the operating behaviours and investment which could deliver the lowest cost in the long run.

The AEMC’s System Strength Review outlines the difficulties of defining system strength in a manner that allows spot market-based procurement, noting as CSIRO does that, currently at least, “system strength lacks a metric” and may be characterised as by the Public Interest Advocacy Centre more as “an outcome, rather than a service”. As such, it is not currently possible to use a spot market for the procurement and pricing of system strength.





As a result of this complexity, FTI highlights the importance of considering centralised, regulated, and/or standardised solutions for the provision of system strength, at least in the medium term.




As discussed in further detail below, structured procurement arrangements could be developed based on contracts, procured by TNSPs or by AEMO, complemented by network provision of system strength services, alongside updating of mandatory technical requirements on generators. These arrangements should aim to ensure the provision of system strength services is valued and procured from an efficient mix of resources procured locally and globally, by individual participants, networks and AEMO to put long term downward pressure on costs.

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<sup>44</sup> AEMC System Services Consultation: <https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system>

FIGURE 22 INITIAL ASSESSMENT OF MARKET DESIGN CHARACTERISTICS OF SYSTEM STRENGTH

<b>Definition and measurability</b>	A system strength service is very difficult to define and measure accurately. It is often a by product of other services	
<b>Scope for competition</b>	Narrow scope for competition as the service is typically localised	
<b>International experience</b>	Little to no international precedent for the procurement of a system strength service	
<b>Scope for co-optimisation</b>	Uncertain potential for co-optimisation with bulk energy and other ESS due to the lack of measurability and its 'by product' characteristics	

**Legend**  Highly favourable to spot market-based ESS  Somewhat favourable to spot market-based ESS  Not favourable to spot market-based ESS

Source: FTI

### Proposed structured procurement arrangements

The intermediate term arrangements for the structured procurement of system strength services will include consideration of:

1. TNSP provision of system strength – there is the potential to build on the existing obligation on NSPs to mitigate shortfalls in system strength identified by AEMO by making the process more proactive, and to provide system strength above the secure minimum. This approach falls within the existing NSP planning processes and can thus provide benefits of economies of scale as well as scope, because TNSPs have the option of entering into contracts with existing resources to provide system strength, or making necessary investments (such as synchronous condensers or network augmentations) under relevant investment tests. While procurement would be driven by the TNSPs (initiated by AEMO's identification of a system need), the scheduling and enablement of the service would likely be AEMO's responsibility.
2. Bilateral forward contracting between AEMO and providers – contracts for system strength provision may take the form of procurement through multi-year contracts for resources (including synchronous generators and synchronous condensers) to come online when instructed to do so by AEMO. The aim would be to give AEMO the confidence that investment in a sufficient volume of resources is undertaken. These contracts could also include provisions that allow AEMO to schedule the resources closer to real time to provide system strength. This approach would require information on the amount of system strength each resource would provide, in order to evaluate which resources to contract with. AEMO would also need to identify system strength requirements over the relevant contracting horizon.
3. Mandatory technical limits – this approach would place technical requirements on parties to mitigate shortfalls of system strength, or to reduce the demand for additional system strength services created by new connecting non-synchronous plant: for example, new resources may be required to invest in inverters that are able to maintain stable operation in an environment of lower system strength, reducing the need for new investments to increase the supply of system strength. This option does not involve any formal procurement or scheduling processes, but it would likely reduce the need for AEMO (or NSPs) to take actions to mitigate shortfalls.

A program of work is underway by AEMO and the AEMC addressing important aspects of system security and network connection relevant to system strength. The AEMC has several rule



changes under consideration. In addition, as noted earlier, ERM and CS Energy have made a proposal into this process which seeks to combine inertia and with other services into a combined “synchronous services” product. When the projected supply of synchronous services is inadequate, AEMO could run a competitive auction to elicit bids from resources to provide synchronous services instead of directing plant. This presents one option considered by FTI as an example of structured procurement.

Like inertia, when supplied by slow-start synchronous generators, delivery of system strength to the power system when needed will require those plants to be committed and synchronised to the system ahead of time. Section 7 addresses the issues of scheduling and ahead mechanisms, and develops the concept of a unit commitment for security (UCS) process. The UCS would be used in the pre-dispatch timeframe to check the right complement of resources will be available to ensure system strength will be maintained, and, where this is not the case, to optimise the commitment of additional resources held under contract. Section 7 develops other scheduling options to enable short term auctions to allow offers from non-contracted resources.

### 6.3. Which options are proposed for further development and consideration?

The ESB has a preference to move toward spot market based procurement of services (the right of Figure 23) when the system and/or technology allows, and when market circumstances make this the most efficient choice. This is because spot market-driven approaches allow the clearest valuation of a service which allows market risk to be not carried disproportionately by consumers, as well as providing investment signals that could support new technologies and entry from new providers of these services.

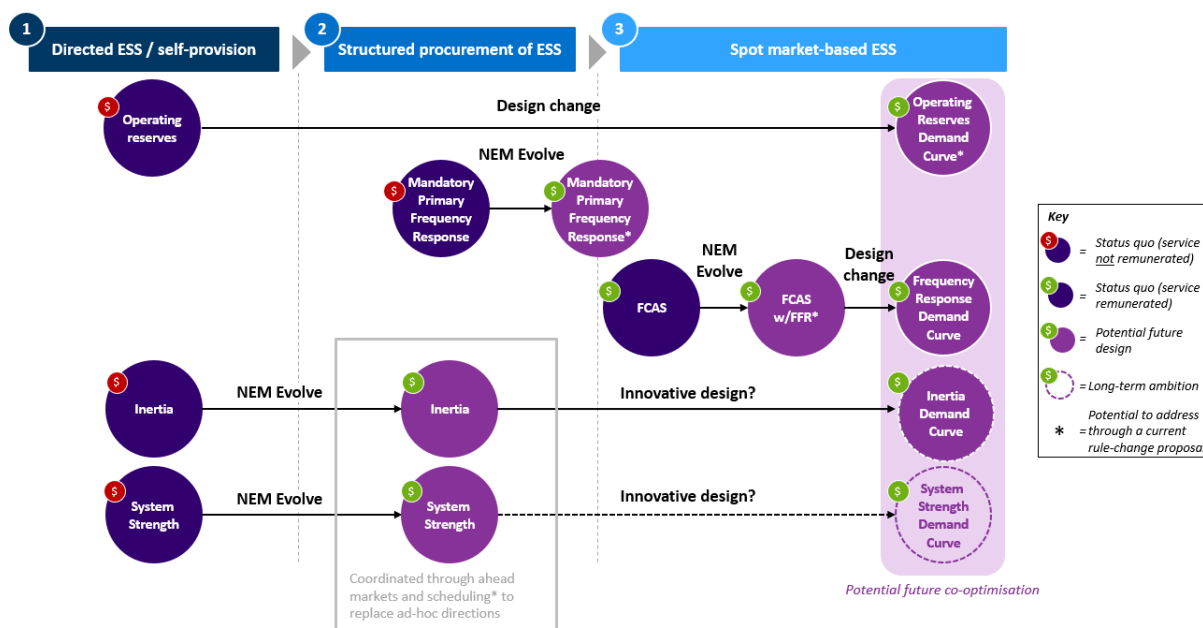
We recognise, however, that some services do not currently appear capable of being procured in a real-time spot market (e.g. elements of system strength), and that regulated/structured provision may be an efficient answer for some time, particularly for capital intensive or lumpy investments. We also note feedback from the Australian Energy Council that a shift toward spot market procurement “should be accompanied by an analysis of the trade-offs in complexity”.

The ESB’s preferred approach is to develop the roadmap outlined in Figure 23 in further detail for the December 2020 Options Paper. Such a roadmap will show reform options that are available now and how the provision of system services may evolve over time. In particular, it will explore options for:

1. Operating reserve procured by a spot market with a demand curve framework, with possible additional mechanisms to support investability.
2. Developing arrangements to incentivise primary frequency response ahead of the mandatory primary frequency response sunset in 2023.
3. Supporting the provision of faster frequency response within the existing NEM framework, with potential for nested co-optimisation and formulation within a demand curve framework.
4. Supporting ahead-scheduling and co-ordination of the provision of inertia and system strength, alongside structured procurement arrangements – such as structured NSP provision, bilateral contracts and generator access standards, or through a PSSAS mechanism.
5. A spot market for inertia in the post-2025 NEM, with co-optimisation with frequency control and operating reserve, with a view for implementation in the medium term.



FIGURE 23 A POSSIBLE ROADMAP OF PROCUREMENT AND SCHEDULING OPTIONS FOR ESSENTIAL SYSTEM SERVICES



Source: adapted from FTI's ESS Report

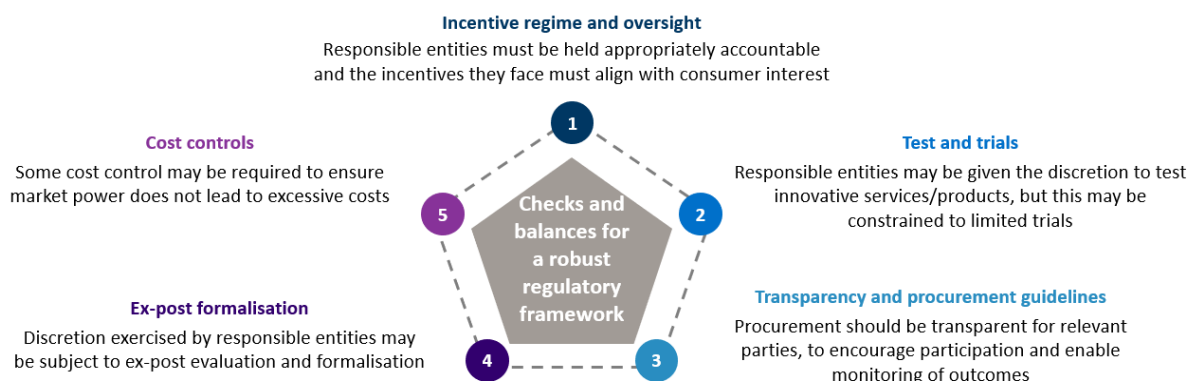
The ESB notes that the AEMC has initiated rule change proposals relating to each of these services. The AEMC is working closely with the ESB to manage these interactions. A guiding principle for any proposed changes is that they are in the long term interests of consumers and consistent with an enduring efficient framework of ESS procurement, with the capability to progress towards greater efficiency when market conditions and technology development indicates it would be possible and beneficial to do so, recognising this may take longer than 2025 for some services.

#### 6.4. Regulatory framework changes

As explored in earlier sections of this Consultation Paper, the ESB recognises that the energy transition will progress at varying speeds over the coming decade and beyond, with varying uncertainty regarding the evolving resource mix. To mitigate the risk of restrictive standards, there may be a case of allowing AEMO and TNSPs a degree of latitude or discretion in the initial stages of the transition. This would allow regulatory bodies to adapt more rapidly if and when conditions change, but would still include mechanisms for oversight, ex-post evaluation and incentive alignment, as outlined in Figure 24, with greater restriction of flexibility as the transition evolves and uncertainty decreases.

In its report, FTI highlights the need for an appropriate regulatory framework to explore this evolving balance between “too much” and “too little” flexibility of the regulatory regime, noting risks associated with each. Too much flexibility risks system operator overspending or operating the system more conservatively than is in the long-term interest of consumers, with little ability for regulators to monitor given likely information asymmetries. Conversely, too little flexibility could “straight jacket” system operators, requiring sub-optimal decisions (including over-spending on resources that are no longer required) and limiting the ability to quickly respond as conditions change. Regulations also need to be sufficiently flexible to allow for emerging solutions (e.g. non-network solutions for TNSPs) while also requiring AEMO and TNSPs to consider these options on an equal, unbiased footing.

FIGURE 24 POSSIBLE CHECKS AND BALANCES OF REGULATORY OVERSIGHT, ALLOWING REGULATORY ADAPTABILITY



Source: FTI

The ESB proposes the continuation of trials, including ‘live’ trials, for participants to gain practical experience with new approaches to procurement and/or scheduling of ESS, and to better understand their benefits and pitfalls. However, the ESB would also like to invite feedback and suggestions on possible regulatory approaches, where both market design and regulatory flexibility evolves through the transition, with perhaps clearly-identified decision points demarcating different stages (such as when levels of VRE, ESS costs, or inertia levels pass certain thresholds). This could include allowing third parties to put forward proposed solutions to identified shortfalls in system services, testing measures via regulatory sandboxing, and providing AEMO a degree of flexibility to make specific adjustments without any ex-ante external review or approval (while other changes would still be subject to more extensive scrutiny and formal regulatory consultation and approvals).

## 6.5. Questions for stakeholders

1. What feedback do you have on the proposed provision of an operating reserve through spot market provision? How could this interact with operating reserve procurement for resource adequacy? Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment needed for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?
2. What are your views about developing FFR with FCAS and developing a demand curve for frequency response? Will such a mechanism help manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?
3. What are your views on the proposed structured procurement for inertia and system strength by way of NSP provision, bilateral contracts and generator access standards, or through a PSSAS mechanism? Which approach is preferable, and what are the relative benefits, risks and costs? Should the ESB instead prioritise the development of spot market for or structured procurement of inertia? What are the relative benefits, risks and costs of such an approach?
4. Given future uncertainties and the potential pace of change, what level of regulatory flexibility should AEMO and TNSPs operate under? What are the benefits, risks, and costs of providing greater flexibility? What level of oversight is necessary for relevant spending? Are there specific areas where more flexibility should be provided or specific pre-agreed triggers?

## 7. SCHEDULING AND AHEAD MECHANISMS – MARKET DESIGN INITIATIVE D

### Key points

Uncertainty and variability in the NEM are increasing under a larger and more complex mix of resources (on both the supply and demand side) and services to coordinate. This leads to greater complexity for the system operator, and increased risks for some participants when making operational decisions. The complexity of efficiently scheduling resources will increase further with large uptake of energy storage, DER and EVs, and the higher reliance on gas-powered generation as coal capacity retires.

The ESB considers that there is a need to develop a solution to coordinating and dispatching resources that essential services across the NEM, some of which (such as synchronous thermal generators) require activation ahead of real-time. This would be implemented in parallel with the procurement options identified in Section 6.

While energy market participants currently manage uncertainties in a decentralised way (including via financial markets and contracts), there may be benefits from establishing new markets to facilitate coordination between parties and co-optimize the delivery of energy and essential services. This has potential to unlock additional value from energy storage, demand response, DER, and the existing thermal generation fleet.

The ESB supports the implementation of a Unit Commitment for Security (UCS) approach to support scheduling system services under contract (rather than a spot market) and systemise how AEMO issues directions to market participants and provide greater certainty. The UCS would complement the establishment of a synchronous services procurement mechanism (covering system strength and inertia).

The ESB is also considering approaches for voluntary, financial ahead markets to procure and/or trade system services (including those that may not have a real-time market), possibly co-optimised with energy.

### 7.1. What is the problem this initiative is addressing?

During the lead up to real-time dispatch, the system operator and market participants must have the tools they need to be able to efficiently coordinate resources. The power system must balance generation and demand and operate within its secure operating envelope. This becomes more difficult in an operating environment of greater complexity and uncertainty, but efficient coordination of resources is critical to meet consumers' expectations of an affordable, sustainable and reliable power system.

AEMO's ISP has highlighted the changing generation mix and, in particular, the major role storage will play in the future, requiring coordination of resources over longer timeframes. The changing resource mix is also investigated in AEMO's Renewable Integration Study which concluded that the power system could be operated securely with up to 75% of underlying demand met by variable renewable sources by 2025<sup>45</sup> if the recommended actions are taken to address the regional and NEM-wide challenges identified.

Participants in the NEM currently self-schedule, determining if and when to operate based on market forecasts. The increased variability of supply, the need for system services whose value does not correlate with energy scarcity prices and growth of distributed energy resources has made it more difficult for some market participants to self-schedule and at times, this schedule

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<sup>45</sup> <https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris>

does not meet power system security requirements, making AEMO's task as the system operator more challenging.

The situation can lead to less than optimal use of resources and, when shortfalls of system services are identified, necessarily causes an increase in *ad hoc* out-of-market interventions to maintain system security. Interventions also contribute to increased costs for consumers.

Most recent out-of-market interventions for system security have been due to the need to maintain minimum levels of system strength. This problem occurs in periods when there is a high proportion of asynchronous generation and a reduced proportion of synchronous generation. The need for these interventions is driven by:

- The lack of a market or other structured procurement mechanisms for some ESS, and particularly for system strength; and
- The source of supply of the needed service being from conventional synchronous generators which need notice ahead of time to start their plant and synchronize it to the power system.

Interventions to manage synchronous resources have mainly occurred in South Australia to date, although they have occurred more recently in other jurisdictions. Scarcity in system strength also leads to curtailment of IBR such as wind and solar generation. This results in higher dispatch costs than necessary. AEMO's Renewable Integration Study highlights the potential for this to occur regularly<sup>46</sup>. As such, it is also expected that the increased complexity of scheduling these resources will extend throughout the NEM, and a market-based solution that does not rely on interventions and is able to avoid uneconomic renewable generation curtailment is required across all regions, not just to manage specific cases.

Interventions highlight the need for structured procurement of ESS (see Section 6), which may require coordination ahead of real time. Going forward, synchronous generators will likely continue to be an important source of ESS, and AEMO will need a process to optimise the procurement of services. The process by which these services are procured in the operational timeframe can be improved.

In conjunction with the procurement of ESS, there may be opportunities to assist market participants to co-ordinate energy ahead of time. For example, slow-start synchronous units may seek to de-risk unit commitment decisions in light of falling operational demand. Energy storage could be coordinated across multiple hours, securing revenue certainty from locking in a pattern of charging and discharging, helping to improve reliability outcomes. Similarly, demand response which requires activation in advance could be scheduled ahead of time, providing revenue certainty for providers. While traditionally demand response has focused on opportunities to reduce demand at peak times, there is an emerging need to shift demand to periods of high DER and solar generation. This provides an opportunity for battery storage and EV charging as well as any electricity demand that is flexible and can shift. Effective co-ordination between the supply side and the demand side can maximise consumers' ability to benefit from the DER in which they have invested.

While these uncertainties are currently managed in a decentralised way (including through financial markets, bilateral contracts, and vertically integrated retailers), additional markets may facilitate better coordination of resources and, critically, allow co-optimisation of new ESS procurement and dispatch (Section 6) and energy (both supply side and demand side) ahead of real time, potentially leading to lower costs to consumers.

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<sup>46</sup> 'Notices of Shortfalls in Inertia and Fault Level (System Strength)' on <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/system-security-market-frameworks-review>

These benefits are driven by a combination of challenges:

- Increasing uncertainty and variability in a more complex mix of resources.
- More ESS to coordinate.
- Essential services not priced in the real-time market.
- Essential services provision being interdependent with priced services (such as energy and FCAS).

### Increased uncertainty and volatility

Pre-dispatch plays an important role in providing an indication of expected dispatch and pricing. The information provided here and in the ST PASA is used by market participants to co-ordinate their resources and self-commit to the market. Pre-dispatch has worked well for this purpose, and stakeholders continue to show support for this arrangement as an effective means for price discovery and informing risk management strategies, combined with the forward contract markets (including ASX futures, OTC trades, and retailing to consumers) providing mechanisms for long term hedging.

However over recent years, there has been increasing uncertainty in both supply and demand translating to an increased uncertainty in pre-dispatch system conditions, from:

- More VRE with inherent weather-dependent variability and forecast uncertainty.
- More DER that is not visible to the operator and cannot be controlled by the security constrained economic dispatch (SCED) process.
- Application of algorithmic and high-volume bidding.
- Dynamic response from participants to changing conditions in the pre-dispatch period up to dispatch.

Uncertainty in pre-dispatch is not just driven from forecast uncertainty. This can be seen by comparing the difference between the pre-dispatch prices and the real-time price with the difference between the forecast and actual residual demand or net load.

Figure 25 shows, for Victoria, the difference between the forecast of residual demand decreasing as the forecast nears real time, as expected. Over the past few years, the accuracy of this forecast remained relatively stable, indicating that forecasting improvements may have been made to offset the impact of an increasing level of VRE (weather-driven output) and DER. The Renewable Integration Study discusses these improvements in forecasting accuracy.<sup>47</sup>

Figure 26 shows that, while the forecast in the expected residual demand has retained its accuracy, there is growing variance in the difference between pre-dispatch and actual prices. A similar trend can be observed in all mainland regions. This indicates that increasing complexity, coupled with the uncertainty, in the system is making it more difficult to project market outcomes. This could affect the efficiency with which resources are used as well as jeopardising system security.

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<sup>47</sup> AEMO Renewable Integration Study, 2020, Section 6: <https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris>

FIGURE 25 ACTUAL LESS RESIDUAL DEMAND FORECASTS (MW) APPROACHING REAL TIME FOR VICTORIA (2011-20)

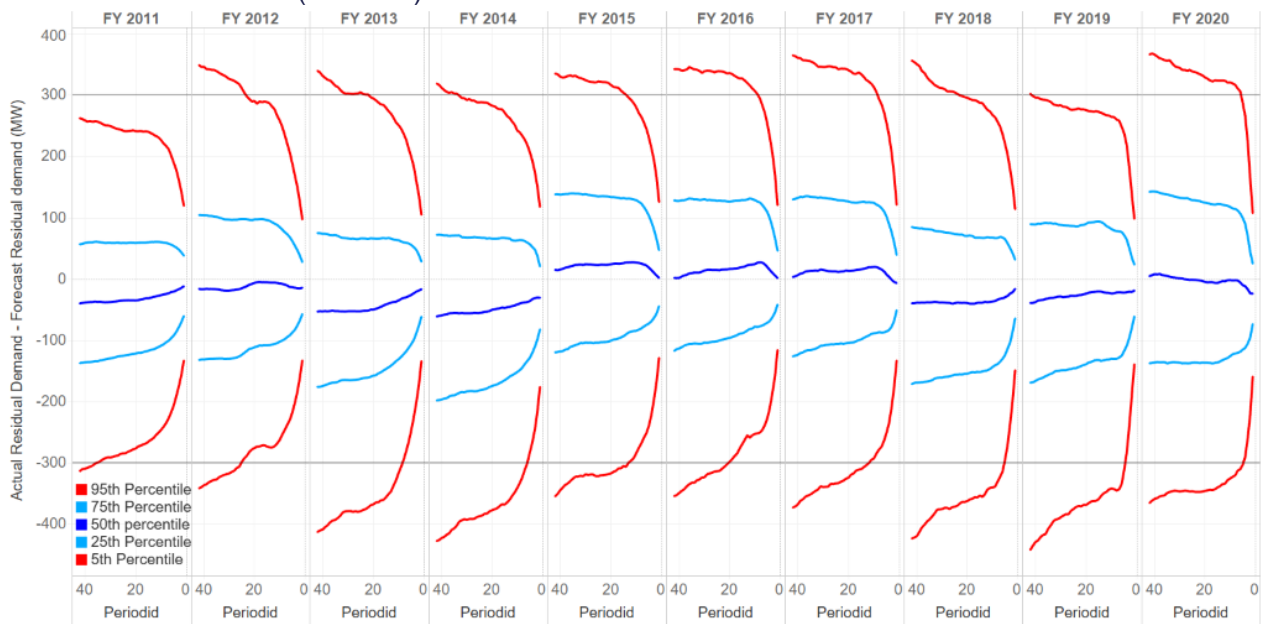
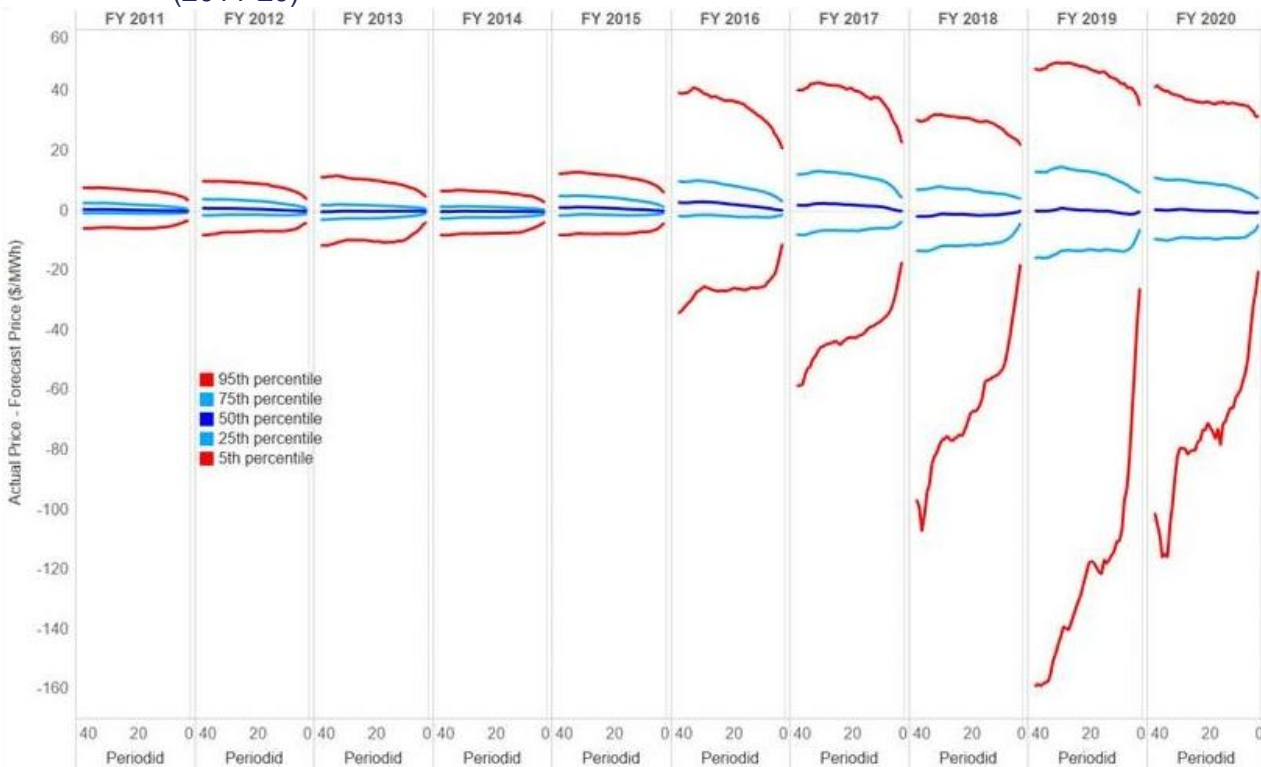


FIGURE 26 ACTUAL LESS FORECAST PRICES (\$/MWh) APPROACHING REAL TIME FOR VICTORIA (2011-20)



### Uncertainty and variability complicates scheduling for market participants

For market participants, more uncertainty in pre-dispatch leads to increased risk in making operational decisions. This has been discussed, for example, by Delta Electricity in its recent rule



change proposal for commitment for synchronous generators<sup>48</sup>. Some participants need to make commitment decisions hours or even days ahead to schedule or pre-position their resource fleet to allow resources to respond to real-time conditions, including, for example:

- A resource providing system services (for example, synchronous generators) that needs a certain amount of notification time to ensure they are online when required.
- An energy storage system which is a very flexible resource, in that it can quickly change its import and export levels, but it critically needs to decide when to charge (or pump) to ensure the resource is in the appropriate state of charge when needed. This is particularly important for shallow storage resources who need to make careful decisions on when to discharge or whether to reserve some charge for a later opportunity or for a different market (e.g. FCAS).
- A resource providing demand response where the ability to provide this may require notice to coordinate operational requirements with the electricity market opportunity.

Participants rely on the signals given through pre-dispatch to make these decisions, and advise their self-commitment decisions to the market via the bids they provide. Bids provided to pre-dispatch must be given in “good faith” and can only be changed in the lead up to dispatch where conditions have changed.

However, with pre-dispatch becoming more uncertain, there are inherently more changes in the pre-dispatch timeframe, leading to changing bids. This in turn leads to a change to the pre-dispatch, creating a circular trend, eventually converging in time towards dispatch. This iterative process is well described in the report commissioned by the AEC and prepared by Creative Energy Consulting,<sup>49</sup> and highlights the dynamic in the importance of the ability to rebid to respond to those changes current market structure to manage the increased uncertainty in the final real-time dispatch.

Furthermore, as also highlighted in the Creative Energy Consulting report, market participants cannot converge on a dispatch that meets system service requirements that are not priced in the market. “The market is *never* going to respond, because there is no price for it to respond to.” The existence of such services undermines the pre-dispatch process unless resources to meet those service requirements are committed early.

### Uncertainty and variability complicates scheduling for the system operator

The system operator also uses pre-dispatch for its operational planning as an indicator of the likely generation dispatch, as per the self-commitment decisions of participants. For the system operator, uncertainty in the pre-dispatch outlook means there is uncertainty in determining whether the system will be secure and reliable for its operational planning. (For example, should approval be given or not for planned outages to proceed?) Indeed, if the system is not forecast to be secure or reliable, it is difficult to determine the most appropriate action to take if there is still significant uncertainty in the generator dispatch patterns.

This situation is heightened if there is uncertainty in the unit commitment, i.e. which resources will be made available and committed to being online. As market participants respond to the pre-dispatch outcomes, and as conditions change, it can be expected that there will be consequential changes in the expected generation profile. Where changes to unit commitment, and thereby resource availability, are made close to real time as a result of the changing conditions, these could have both system security and economic consequences, as they limit the ability for the system operator to respond and the choices available, potentially leading to higher cost interventions.

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<sup>48</sup> <https://www.aemc.gov.au/rule-changes/capacity-commitment-mechanism-system-security-and-reliability-services>

<sup>49</sup> Scheduling and Ahead Markets - Design Options for Post-2025 NEM', Report prepared by Creative Energy Consulting Pty Ltd for Australian Energy Council, June 2020



## Opportunity to improve efficiency

An ahead mechanism could provide market participants an additional mechanism (in addition to the contract market) to manage risk and maximise value. To ensure the dispatch can effectively utilise all resources and co-ordinate their scheduling to meet these needs, there is a need to examine the different technologies and associated behaviours and how they interact with the dispatch market design and can manage their risk profiles.

Potential use cases that are being explored through this initiative include:

- Activating additional system services for market benefits.
- Establishing a platform to hedge system service costs.
- Facilitating greater DER and demand response participation.
- Improving scheduling of storage including EV charging.
- Providing a new mechanism to hedge against short term variability.
- Improving coordination between electricity and other markets (e.g. gas).

The relative value of system services is likely to increase, and thus may benefit from different options for management of the risks associated with delivery and the cost of provision. Incentives for self-commitment will be retained with valuing the services and enabling contracting against the price of that service. An ahead platform provides an avenue to manage this commitment and associated risks.

In order to efficiently integrate high and growing volumes of DER into the system and capture more value on the demand side, their participation in the dispatch framework should be considered. Some demand response and DER resources currently face barriers to participate in the current market framework due to:

- Long notification time.
- Inflexible operational characteristics (e.g., min-on/off or lumpy output level).
- Uncertainty of value received via changing consumption profile.
- Coordination complexity and inability to respond to real-time price signals resources in the distribution network.

The ESB has received feedback from some demand response providers that greater certainty over the commercial returns, hours or a day ahead of time, would improve the ability and willingness of some consumers to make their load flexible. While some loads are very flexible at short notice, others need to prepare their operations. The lack of confidence in pre-dispatch prices presents a barrier to participating in the wholesale electricity market. This could also apply to distribute energy resources.

Storage is projected to become an increasingly important and prevalent part of the resource mix of the NEM, potentially for the supply of ESS, operating reserves and energy. The optimal use of storage requires careful use of the capability, especially for those with a limited, or shallow, level of storage. Improved ahead market arrangements could assist participants with storage to maximise the utilisation and hence revenue from their assets.

## 7.2. What are the options considered?

### Short to medium term actions

In parallel with the urgent actions, the ESB and market bodies have been considering further action with implementation of initial reforms proposed for the short to medium term. In March 2020, the ESB published four options for incorporating an ahead mechanism in the NEM. The

options ranged from a least change – a Unit Commitment for Security (UCS) mechanism – through to a full, mandatory ahead market involving physical commitment. The table below sets out the potential options for introducing ‘aheadness’ to the NEM.

TABLE 5 AHEAD MECHANISM DESIGN OPTIONS

1. UCS - only	2. System service ahead scheduling	3. Integrated ahead market	4. Compulsory ahead market design
<p>The UCS is a system analysis and optimisation tool. It optimises across time constraints, location and costs.</p> <p>It can be used to schedule non-market system security service contracts held by AEMO or TNSP (e.g. for system strength and inertia).</p> <p>Using participant self-commitment in pre-dispatch, the UCS can identify if and which additional units are required to commit to satisfy system service requirements with regular publishing of information.</p> <p>Where system security requirements are not met, AEMO resorts to directions processes as it does today and uses the UCS to support this process.</p>	<p>Takes UCS and adds the ability to trade or procure system services (including contracted services) before real-time on a voluntary basis.</p> <p>Design options:</p> <ul style="list-style-type: none"> <li>• Procurement via publication of forecast requirements (e.g. using UCS, pre-dispatch) bid stack or auction process to source inertia, system strength., considering any structured procurement.</li> <li>• Ahead market arrangements to source frequency and operating reserve ahead of real time providing ability for new technology to participate in services markets.</li> </ul> <p>Where the service is priced in a real-time market, participation in the ahead market would be voluntary and commitment would be financial.</p> <p>The UCS remains as a decision-support tool for the system operator.</p>	<p>Co-optimised ahead scheduling of energy and system services. Combines both the previous options and adds the ability for participants to trade energy on an ahead basis in a co-optimised manner.</p> <p>Where the service is priced in a real-time market, participation in the ahead market would be voluntary and commitment would be financial.</p> <p>Provides additional avenues for DER and demand response to participate and scheduling certainty for storage resources.</p> <p>The UCS remains as a decision-support tool for the system operator.</p>	<p>Mandatory participation for all energy and system service resources.</p> <p>The UCS remains as a decision-support tool for the system operator.</p>

### Option 1: Unit Commitment for Security (UCS)

The UCS process is based on an analytical tool that seeks to give AEMO an enhanced ability to identify and address security and reliability shortfalls in the operational pre-dispatch timeframe (equivalent to up to 40 hours ahead). The tool combines *systems analysis* to identify any shortfalls and an inter-temporal *optimisation-based unit commitment model* that can determine the optimal additional commitment to remedy any shortfalls identified.

The UCS runs automatically and at regular intervals, just like the current pre-dispatch and PASA processes. Each time it runs, the UCS performs its assessment based on the latest unit commitment schedule as indicated in pre-dispatch.

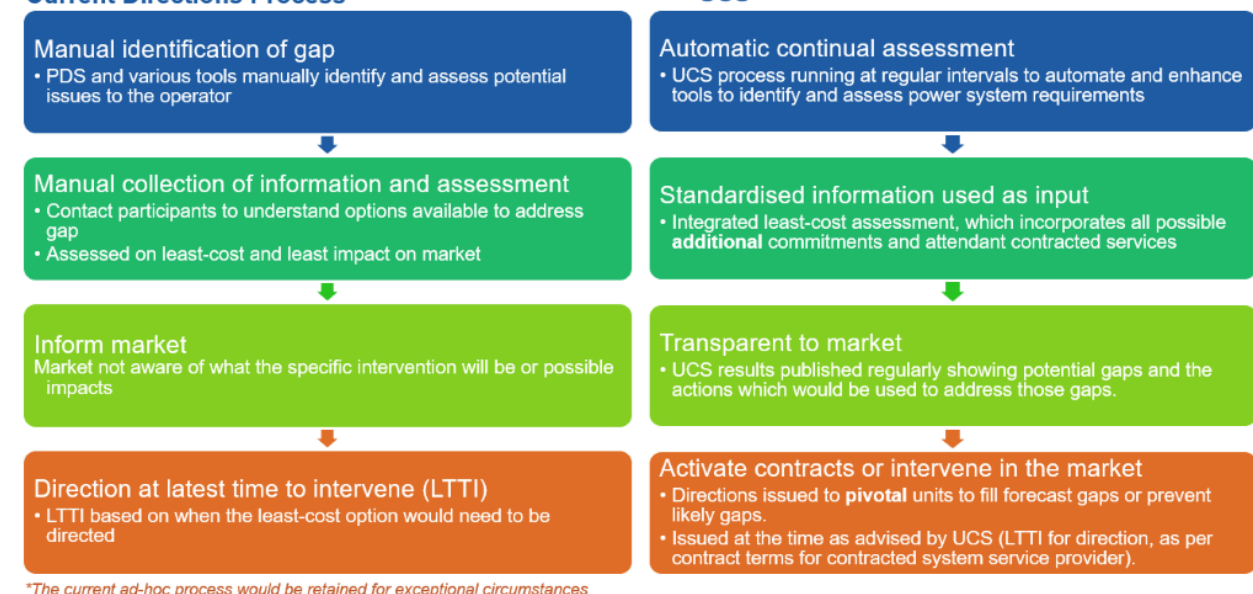
As the UCS runs regularly, it is able to identify if and when the provision and need for these system services changes through the operating period and indicate to activate contracts as required or flag these potential shortfalls to the market to allow participants to respond.

The UCS option enables AEMO to:

1. Schedule non-market system security contracts held by AEMO or a Network Service Provider (NSP) (e.g. for system strength and inertia).
2. Where system security or reliability shortfalls exist, support identification of last resort interventions more efficiently and transparently, if the market does not respond to earlier UCS notifications of gaps shortfalls.

An overview of the UCS tool and process is described in more detail on the ESB Post-2025 program website. The figure below shows how the UCS can be used within option 1 – as a decision support tool – compared to the current intervention process.

FIGURE 27 THE CURRENT DIRECTIONS PROCESS AND UCS



Important points to note about the UCS process are:

- The UCS would utilise data and information provided by AEMO and market participants regarding technical requirements and attendant costs to be able to identify the least-cost intervention, where required. This information could be provided on a standing basis, and updated as needed in the circumstances a potential gap in system requirements has been flagged to reflect the conditions on the day.

The UCS would be run regularly with results published. Where the UCS has identified a potential shortfall in a system requirement, this will be indicated to the market, providing time for the market to respond, prior to AEMO intervening, as per current practice.

The UCS would provide improvements over the current process by systemising data provision, having enhanced optimisation, and providing greater transparency to the current ad hoc and specific processes requiring significant manual collection of information and assessment.

To date there has been broad support from stakeholders in relation to the UCS proposal. There is also support to improve the intervention and directions framework with a more automated and standardised approach.

## Option 2: System service ahead scheduling

This option builds on the UCS and establishes an ahead market to facilitate the trading and scheduling of system services ahead of real time. These ahead markets can enable the procurement of services for system security including via a market-based process. This allows for consideration of resources beyond those which may have a long term contract under the structured procurement method, and procurement of services with a real-time price under a financial commitment.

In the March 2020 ESB paper on System services and ahead markets,<sup>50</sup> this option was described as introducing a platform that brings together participants who wish to trade energy or system services ahead of time. This may also include AEMO (as the system operator) purchasing some system services ahead of time. This option is being refined to focus on the voluntary trading and procurement of system services, including trading and scheduling of system services ahead of real time, but not energy. The potential inclusion of voluntary ahead trading for energy will be considered under Option 3.

An ahead market for system services is able to take into account both long term contracts for system services (such as those procured through the options considered in Section 6), and offers for the provision of the service on the day via a bid stack or auction process to schedule services that may or may not have a real-time market. For those which do have a real-time market, ahead market arrangements can provide a short term hedge which could firm prices for users of the service, secure revenue for providers and incentivise their compliance to commit plant. For those services that do not have a real-time market, this option can enable competitive provision of the services procured under a structured framework.

The ahead market can involve AEMO as the central buyer and also be designed as a two-sided platform where participants can trade among themselves to manage the cost and risk of system security services. Where AEMO is the central buyer, administratively set demand curves based on the forecast system conditions can be used to drive the procurement of the system services. This is also examined in Section 6, where spot market-based procurement is discussed.

For services that are compatible with real-time spot prices, it is proposed that participation would be voluntary, and the ahead schedule financially binding, so that a deviation from the ahead schedule would be settled against the real-time price. For services that do not have a real-time spot market, an alternative design may be required for the settlement of any deviation from an ahead schedule given there is not a clear reference price. An option could be to expose these participants to the cost of any action required to fill the resulting gap or to apply penalties under the contract terms and conditions.

The UCS would also be a part of this option as a backstop measure for the system operator if there are any system requirement gaps that are not being met by the market but could be addressed by additional generating units online.

## Option 3: Integrated ahead market

An integrated ahead market would incorporate energy trading and the co-optimisation of energy and system services in the ahead market design. To the extent possible, the ahead market would co-optimize across the energy market and system services and between the markets for different system services. Like Option 2, for services that are compatible with real-time spot prices (including energy), the ahead schedule would be financially binding with deviations being settled at the real-time spot price, and as such the ahead market still provides an opportunity to hedge risks associated with system service provision.

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<sup>50</sup> ESB System Security and Ahead Markets, April 2020: <http://www.coagenergycouncil.gov.au/post-2025/system-service-and-ahead-markets>

The integrated ahead market allows for the scheduling of resources whereby participants can utilise the market platform to co-optimize their scheduling with that of the system needs while providing a platform to trade risk and secure revenue certainty for their operations. By adding energy into the ahead market, the procurement of system services in the ahead timeframe can be assessed against the expected energy, allowing participants to:

- Offer system services in such a way that the market scheduling process considers the provision of energy with the provision of system service, where these are interdependent. In an integrated ahead market, participants can make an ahead market energy offer alongside their system service offers. The scheduling process would take both into account. Compared to scheduling individual services in silo-ed ahead markets, the overall schedule under this option will be more efficient. As a result, the combined schedule is also likely to lead to a better outcome for participants, maximizing the value from their resources. This includes system services which do and do not have a real-time price, such as operating reserve and system strength respectively (where these are introduced).
- Utilise the ahead market to secure the provision of additional system services to reduce the curtailment of low cost generation where there is a willingness to pay for that service. For example, where additional system strength provision can be procured to avoid the curtailment of an IBR with low-cost energy, this may be better facilitated by an integrated ahead market.
- Produce a base schedule for resources that require advanced notification, including slow start generation, demand response, DER, and storage facilities. This base scheduling can also facilitate greater co-ordination between participation in the electricity market and participation in other sectors.
- Provide a platform for short-term hedging of energy and allow participants to fine-tune their financial obligations aligned with the physical conditions on the day.

Work on this option is focused on developing an ahead market design where participation is voluntary, and the ahead market trading stands alongside the real-time market processes rather than being a direct component of the pre-dispatch process. This will allow separate bidding into the market while retaining the functionality of the pre-dispatch to provide an indication for the real-time dispatch.

With this design, there are effective linkages between the ahead market and pre-dispatch, as some information for the ahead market is drawn from pre-dispatch and the outputs of the ahead market would make their way to the pre-dispatch schedule via participant bids and offers, and ultimately in dispatch. Participants with an ahead market position would have an incentive to reflect these trades in their bids in the real-time market unless market conditions make it more profitable to use their flexibility and vary from the ahead market schedule (which would be of benefit to the system) or to reflect a change in their physical availability. This continues to reflect the self-commitment nature of the NEM.

With an ahead market facilitating energy trading, there would now be two reference prices for energy aligned with operations to which forward contracts could be referenced: the ahead or the real-time energy price. It can be expected that the majority of forward energy contracting will be aligned to the place where the most trade occurs.

In Option 3, similar to Option 2, the UCS remains important as a backstop to maintain security and support the system operator, ensuring any intervention required is efficient and transparent.

#### Option 4: Compulsory ahead market design

Option 4 is similar to Option 3 in that all energy and system services are scheduled ahead and co-optimized to the extent possible. However, this option requires all resources to participate in



the ahead market and the ahead schedule can be physically binding even for services that have real-time spot prices.

This option is not described in more detail here, as the ESB does not wish to proceed with this option at this stage. The ESB considers that the voluntary ahead market options described above are likely to be broad enough in scope to meet the desired objectives while allowing the market to adjust to real-time conditions. Stakeholders have also expressed concern with this compulsory ahead market option, because it can limit flexibility and moves away from the self-commitment nature of the NEM. A compulsory and physically binding ahead market design also has the additional need to resolve how to achieve flexibility to adjust the ahead schedules if there is a need or a benefit to do so.

### 7.3. Which options are proposed for further development and consideration?

At this stage the ESB generally supports:

- The implementation of the UCS approach.
- The development of options 2 and 3 – a voluntary ahead market to procure and/or trade relevant system services (with or without energy) with a financial commitment.

The ESB agrees with those stakeholders who expressed concerns about the viability of Option 4 in the NEM and does not propose to develop this option further.

The UCS is considered the minimum that should be done, and steps can be taken now to facilitate its implementation ahead of 2025. The UCS provides a safeguard mechanism to ensure security and enhance AEMO's ability to address system gaps. While the UCS may be implemented before the other options under this ahead market initiative, implementation must consider the potential evolution of the market.

A key dependency is that additional system services are defined, valued and remunerated for their provision, either through a "spot market" (ahead and/or real-time), or via contractual or regulated arrangements, as considered in Section 6. These systems services need to be scheduled, and it is the intention of this MDI to develop mechanisms to achieve a reliable and secure system through the transition and beyond.

As the ESB develops each option for ahead mechanisms, we will consider what tools market participants and the system operator may need to enable efficient system-level coordination of resources. Dispatch outcomes must remain within the secure operational envelope. The following objectives are worth noting:

1. Improve security and reliability outcomes in the NEM by ensuring resources are available in real time.
2. Improve scheduling efficiency in delivering a secure and reliable system, through a market-based mechanism where possible, in order to lower total cost to end consumers by allowing the market to respond to the prevailing market conditions.
3. Facilitate the energy transition by:
  - a) Supporting the transition of the resource mix to support as high VRE penetration and demand participation as is physically and economically viable.
  - b) Promoting consumer engagement and DER integration by facilitating the uptake and coordination of demand response and DER resources.
  - c) Utilising the existing fleet during the transition, but not prolonging asset life beyond what is economically efficient.

At a high level, the ESB considers that the UCS-only option can deliver against the first objective by providing a mechanism to schedule system services that may not have a real-time market, and improving the intervention process when this is required. However, there may be potential value to be realised by moving to Option 2 or Option 3. For detail of how each option facilitates meeting the objectives and the various use cases, see the paper provided on the ESB Post-2025 program website.

#### 7.4. Questions for stakeholders

1. The ESB is interested in stakeholder feedback on the options for the ahead mechanisms we have outlined. Are there additional options? Are the options for a UCS and UCS + ahead markets fit for purpose?
2. The ESB proposes to develop the UCS tool for implementation. Do you support the UCS concept? What factors and design features should be considered for detailed development?
3. The difference between actual and forecast residual demand leading up to real-time dispatch has been far more stable in the last decade than the difference between actual and forecast prices (\$MWh) leading up to real-time dispatch. What do you consider the drivers of this may be?



## 8. TWO-SIDED MARKETS – MARKET DESIGN INITIATIVE E

### Key points

The changing system dynamics and growth of decentralised sources of supply is a contributing source of variability and uncertainty in the system. This can create costs and can increase energy prices for consumers. There is an opportunity to change the current NEM arrangements to make it easier for new types of participation in the market, or for consumers with flexible demand to participate. This would improve visibility and understanding of flexible demand on the system and provide more choices to consumers. This also means that consumers could be rewarded where they shift their demand to other times of the day when they can offer valuable sources of flexibility to the system through different market services or mechanisms.

This workstream sets out a long term approach towards two-sided market arrangements. This progressive approach is intended to:

- Allow consumers to choose if and how they participate in the wholesale market
- Better reward the value provided to the system by flexible demand and supply
- Facilitate new types of participation in the market, remove barriers and provide incentives for traders to participate in dispatch, enabling greater innovation and choice to consumers
- Work out how best to incorporate price responsive supply and demand into the operation of central dispatch and the forecasting that leads into real time, enabling better informed quantity and price inputs from both the demand and supply sides in market processes
- Establish an evolved consumer protections framework that makes sure all consumers have fit-for-purpose protections.

This program of work dovetails with the DER integration workstream and aims to provide a framework that will allow DER to participate fully in the wholesale markets. How the two workstreams are structured going forward will be considered further by the ESB.

### 8.1. What is the problem this initiative is addressing?

The transition underway across the NEM is creating opportunities as well as challenges, and the opportunity to develop a two-sided market further can make a large and valuable contribution to both consumers and the system as a whole.

Currently, there are a number of retailers and third party service providers that either utilise demand response or enable consumers to do so themselves through retail products or price signals. The responsiveness of the demand side, and the ability of consumers to access value associated with demand response, is growing and will continue to grow. This MDI is exploring how to continue to grow the capabilities of the demand side to respond and, at the same time, considering how this burgeoning response should be incorporated into the market frameworks.

As noted earlier (see Section 2) the NEM is shifting from a sole focus on electricity supply to a market where changes in demand are also important. The traditional three-way relationship between retailers, distribution companies and consumers is also changing. Consumers used to engage with their retailer predominantly when they paid the bill or switched retailer, and paid attention to their distributor only during outages. This is changing. There are large volumes of DER, and an increasing number of consumers who produce energy and whose demand can be more flexible than previously. This workstream complements the work being undertaken in the Integrating DER work program (discussed in Section 9 of this paper).

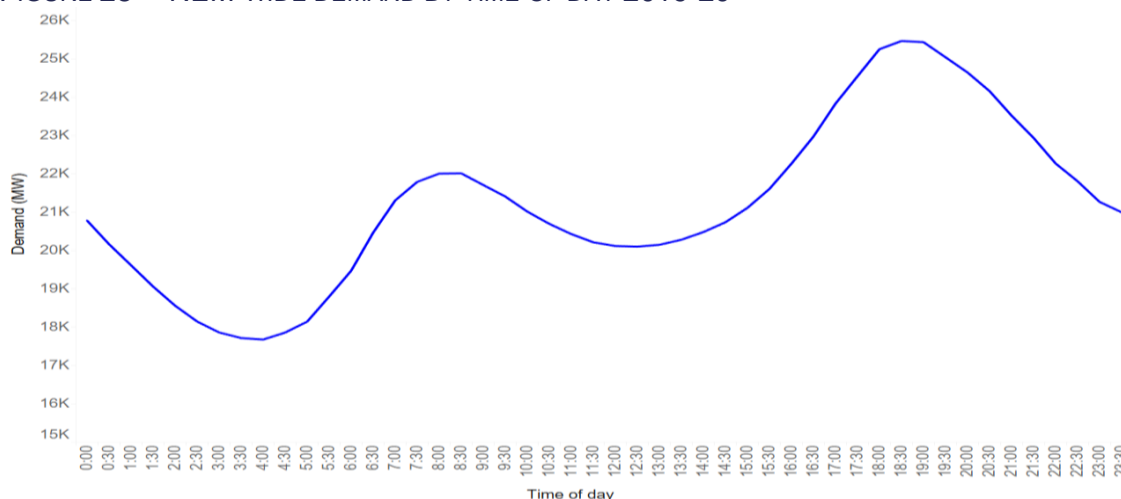
Changes are also occurring beyond the electricity industry, driven in part by digital technology. Examples include:

- An increase in smart appliances and smart meters, where retailers, aggregators and others are creating new opportunities to create value for consumers.
- The introduction of new innovative retail products (such as the aggregation of pool pumps for demand response).
- Consumers not needing to monitor electricity prices and decide how or when to participate in the market, as these decisions are set up to happen autonomously.

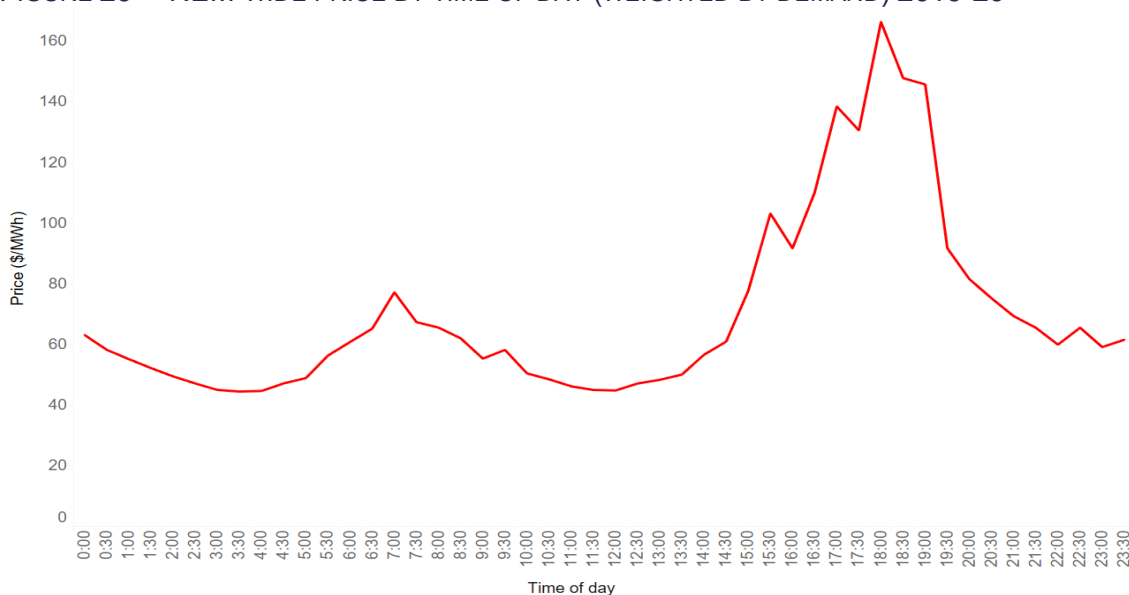
Realising the potential to create value through flexible supply and demand (including from DER) offers efficiency benefits where flexibility in demand and provision of DER services into the wholesale market could increase competition and reduce the marginal costs of supply, providing overall benefits to consumers.

As Figure 28 below shows, the demand for electricity across a 24-hour period tends to peak in mornings and evenings (with lower minimum demands being experienced in South Australia also illustrated in Section 2). The wholesale cost of electricity per MW, by contrast, is driven by generator availability. Prices are shown in Figure 29.

**FIGURE 28 NEM-WIDE DEMAND BY TIME OF DAY 2019-20**



**FIGURE 29 NEM-WIDE PRICE BY TIME OF DAY (WEIGHTED BY DEMAND) 2019-20**



In the middle of the day, between the demand peaks, power is least costly as wind and solar are typically at higher availability (at zero fuel cost).

To the extent customers can shift their demand to periods when power is cheapest (the middle of the day in Figure 28), and away from more expensive periods, there is value to be made for all consumers through the resulting cost savings in network buildout and smoothing of peak demand and reducing generating capacity to meet peak demand. And, as the discussion above notes, there are now digital tools and smart appliances that make this possible.

The current market framework makes it difficult for consumers to participate in a way that can reward or value the reduction or shift of the timing of their demand (or use of their DER). While large consumers with high energy demand and the ability to flex that demand have been able to respond to prices and have the technology in place to allow them to respond, smaller consumers have been less able to participate, especially those that do not receive price signals reflecting changing market conditions. Small consumers are able to respond to some price signals, such as time of use tariffs, and access technology such as smart meters and DER. This means the capability of the demand side to respond to prices will continue to develop. The growing flexibility of demand side resources and DER, fuelled by new and advancing technologies, and digitalisation, is now fast becoming a substantive element of the market and the issue is to ensure that all consumers can access this value.

It is also important that the value that can be achieved is not simply related to the energy saved at expensive times of the day (or season). Having greater certainty regarding how both demand and supply (and system services) would be dispatched or respond to price is valuable too. Flexible demand can respond to signals and help avoid direct and costly interventions in the market that are necessary when supply is not adequate to balance the system; and in the longer term where customers can provide flexibility in their demand, this response can be used to lessen requirements for new investment in generation. In this sense the value of a MW of demand saved is equivalent to the cost of a MW of supply that does not need to be generated, and that value varies with the time of day, seasonal requirements and operational events.

## 8.2. What are the options considered?

### The objective of the market design options

The options considered for the two-sided market have a dual objective:

- First, to design a market that supports the most efficient balance of supply and demand.
- Second, to enable all consumers to realise the value of their demand and supply.

### Meeting customer needs

While services for a two-sided market are emerging, many consumers are not yet receiving great outcomes from the current arrangements. The two-sided market design work is focused on progressive changes to the market.

To improve customer outcomes, the new market design needs to reflect the following practical outcomes:

- *Provide choice and enable innovation* – current arrangements restrict how consumers can access products and services from providers. For example, people can currently only contract with one retailer at a connection point, which means they cannot easily engage with other intermediaries (such as aggregators). Consideration needs to be given as to how future arrangements can best support the range of ways in which all consumers may want to receive their energy services in future – for example through a VPP or perhaps a bundle of energy products. Consumers should not have to participate or engage any more than they do today, unless they want to.

- *Ensure consumers are treated equitably* – many energy consumers have limited means, ability and/or interest in actively participating in markets for energy products and services. It is important that the market design provides choice and easy opportunities for consumers to engage where they choose to do so and have appropriate protections for consumers whether or not they engage.
- *Create opportunities to lessen the ‘energy divide’* – there are community-based initiatives elsewhere that we may be able to learn from, such as community-based batteries that reduce local network congestion and improve network access for all types of consumers connected to that part of the network. Regulatory frameworks may be able to complement and support community outcomes.
- *Provide incentives on third parties to partner with consumers* – the framework should be set up to encourage third parties to offer services to consumers that enable them to receive value for the flexibility of their demand or DER resources (that in turn helps third parties to balance their portfolios).

Proceeding with practical approaches along these lines is expected to reduce system costs and complexity. Costs reduce because greater visibility of demand helps reduce uncertainty regarding demand forecasting, reduces the need for additional system reserves, and lowers the costs of operating the system. Increased access to demand response and DER also broadens the pool of potential service providers, ultimately avoiding investment in networks and new generation where flexible demand can be used to support load shaping. Demand-side flexibility provided by those consumers who choose to participate enables more efficient system operation and reduced costs for all consumers.

The complexity of existing arrangements can also be reduced. Complexity is a barrier to engagement and a significant contributor to the ability and motivation of consumers to engage in better offers. New arrangements should not come at the cost of increased complexity to customers, and it is therefore important that the design of two-sided markets is developed with and informed by engagement with consumer stakeholders.

Appropriate consumer protection is essential. New market models, products and services (particularly for an essential service such as electricity) can raise new risks for consumers, for those consumers who may be disengaged or vulnerable. With new products and services, it is vital to maintain consumer confidence, with protections against the risk of parties whose business practices are not necessarily appropriate. A foundation of protections must be in place for all consumers, no matter their specific circumstances.

In considering the market design for a two-sided market, the ESB will use Energy Consumers Australia’s (ECA’s) Supporting Households Framework<sup>51</sup>, to help identify where other complementary measures may be appropriate to support improved outcomes to consumers who may not have the means, ability or motivation to engage in new market offerings. With complementary non-financial measures, there is a potential to increase the proportion of consumers that may be able to engage in two-sided market offerings, increasing value to those consumers directly, and reducing uncertainty and improving outcomes for all consumers at a system level.

Use of customer archetypes can provide a clear view of the:

- Types of consumers who can achieve the greatest benefits from the two-sided market (noting that all consumers will benefit from a more efficient market).
- Protections that should be made available to all consumers whether they are actively participating or not.

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<sup>51</sup> <https://energyconsumersaustralia.com.au/publications/supporting-households-to-manage-their-energy-bills-a-strategic-framework>

- Consumers who may require assistance and the areas where they are likely to need that assistance. This can enable specific targeted programs to be considered by governments and policy makers.

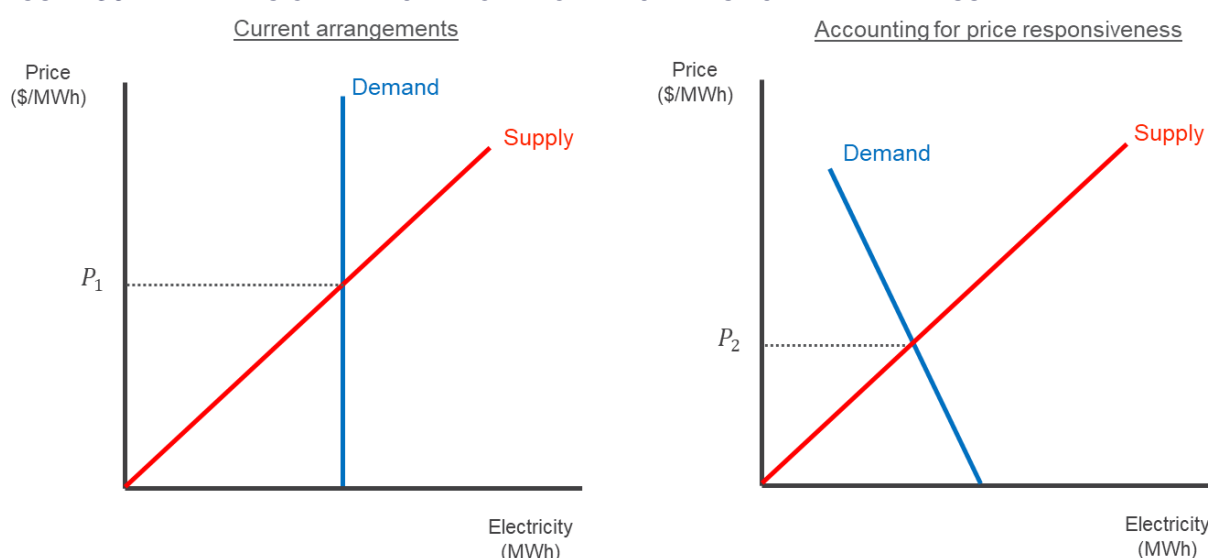
For further detail regarding the proposed use of the ECA framework, see the ESB Post-2025 program website or the ECA's Supporting Households Framework.

### Meeting the needs of the system

The changing system dynamics and growth of decentralised sources of supply is contributing to variability and uncertainty in the system. This creates costs and can increase energy prices for consumers.

Having price responsive demand and supply is good for the system. It helps align supply and demand and results in a better utilisation of the power system. As noted above, all customers have different motivations or opportunities to engage in the market. However, overall, when consumers and producers make efficient decisions, it leads to an efficient clearing of the spot market; that is, the intersection of supply and demand results in a price and quantity that maximises the benefit to both producers and consumers of electricity. This is highlighted in the stylised Figure 30 below.

FIGURE 30 BENEFITS OF PARTICIPATION FROM PRICE ELASTIC DEMAND AND SUPPLY



In the present market design in the NEM, only batteries or large hydro pumps participate in the wholesale market as scheduled loads. These loads are the only source of price responsiveness in the demand side that is taken into account in clearing the wholesale market, despite the fact there are other consumers who can and do respond to wholesale prices.

Instead, consumers' demand is included in an aggregate central forecast. These aggregate central forecasts are becoming increasingly uncertain, partly because there is limited visibility of the intentions and price responsiveness of demand. These limitations cause forecasts to be more inaccurate and lead to inefficient decisions by consumers, generators and AEMO, which in turn lead to increased costs for consumers.

In the long term, increasing uncertainty in demand may lead to increases in the resources procured and scheduled by AEMO for unexpected contingencies (e.g. RERT), the build of additional and unnecessary generation, and the inefficient build out of networks to deal with peak demands that could be smoothed out by end users choosing to shift their flexible demand. All these issues lead to increasing costs for consumers.

The two-sided market work specifically promotes the effective uptake and utilisation of DER and demand response by:

- Establishing a framework for the trading of ‘services’ in the market as opposed to asset-level obligations and performance requirements – supporting higher levels of flexible capacity and facilitating innovation in services for consumers.
- Evolving the market design to provide spot price signals that enable flexible two-way supply and demand resources to engage at all connection points.
- Simplifying the participation framework to support traders of services to aggregate connection points (including those with installed DER) to provide services and participate in energy and ancillary service markets, where they meet the service specifications.
- Continuing to move from the existing arrangements where tariffs do not necessarily encourage DER to export to the grid at times of surplus, to a pricing framework that would incentivise DER to use the network (whether for export or charging) when it is not congested and at times when DER is valued by the wholesale market. Over time, this creates significant opportunities to reduce system costs and therefore, consumer prices.

This workstream complements the work being undertaken in the Integrating DER work program and DER Integration Workplan (discussed in Section 9).

## Options and their time frame

### Steps already underway

Changes are already in place or underway in the market to encourage greater demand side participation and the provision of demand response. In summary, these changes are:

- *A move to five-minute settlement* – sharper price signals align better with physical operations, leading to more efficient bidding and operational decisions. Participation of fast response technologies, such as batteries, fast-start plants and demand response, is expected to be encouraged.
- *The introduction of the demand side portal and the DER register* – in 2015, the AEMC made a rule so that AEMO can obtain information from participants on demand side participation in the NEM. The portal continues to evolve by accommodating more granular information associated with different types of demand ‘adjustments’ (i.e. not just curtailment). This improves the quality of inputs into some of AEMO’s load forecasting processes. In 2018, the AEMC made a rule to introduce a DER register. The register will give network businesses and AEMO visibility of where distributed energy resources are connected to help in planning and operating the power system as it transforms.
- *Power of choice reforms* – key reforms making it easier for consumers to engage in the energy market:
  - Cost-reflective pricing – introducing distribution prices that better reflect the different ways households and businesses use energy. The rules provide better signals to consumers to reduce their peak demand and to optimise the use of their DER.
  - Competition in metering – through moving to smart meters, giving consumers more opportunity to access a wider range of electricity services and gain better information about how they can change their electricity use to save money.
- *VPP Demonstrations* – the AEMO VPP Demonstrations are delivering valuable insights informing how aggregated DER can bid, share operational and telemetry data, and be coordinated to deliver FCAS. The VPP Demonstrations have been extended to June 2021 with the number of VPPs and the aggregated VPP capacity continuing to increase.



- *Victorian DER Marketplace* – the Victorian DER Marketplace includes a demonstration of the co-ordination and optimisation of aggregated DER in the wholesale market within distribution network limits as well as the provision of local network services.
- *ARENA/AEMO demand response RERT trials* – in May 2017, ARENA and AEMO partnered for a three-year trial of demand response services using the RERT (emergency demand response) arrangements.<sup>52</sup> This initiative demonstrated that demand response is an effective source of reserve capacity for maintaining reliability during contingency events, and that demand response resources can be rapidly developed for deployment. These resources have been used numerous times, particularly in recent summers, to assist with managing power system reliability. RERT resources can avoid or reduce the need to instruct involuntary load shedding under extreme conditions.
- *Wholesale demand response mechanism (WDRM)* – in June 2020, the AEMC made a final rule to facilitate wholesale demand response in the NEM. Under this rule, large consumers are able to sell demand response in the wholesale market, either directly or through specialist aggregators. The mechanism commences on 21 October 2021.

In its final determination on the demand response mechanism, the AEMC noted that the growing number of consumers equipped to actively participate in the market will eventually lead to the market outgrowing this particular mechanism. In the meantime, the mechanism will be important for enabling a greater level of demand side participation in the wholesale market, providing valuable insights into the best approach for incorporating greater demand side participation through a two-sided market, particularly in terms of forecasting and scheduling.

### Next stages of reform

In addition to the changes to promote options for consumer engagement outlined above, additional steps are needed to facilitate an expanded two-sided market beyond 2025. The workstream focuses on the following timeframes:

- Short term (now to two years) – options emphasising the opportunities for consumers to participate in the market through aggregators and traders.
- Intermediate term (two to five years) – beyond the short term, changes that revise the current mechanisms for scheduling, dispatch and forecasting to encourage greater levels of participation in the market. Work will be undertaken to improve processes relating to registration and classification.
- Long term (five years and beyond) – continuing to increase the opportunities available to traders to enter the market and provide new services. This should improve the ability for traders to unlock the value consumer demand and DER for provision of energy, demand response and other services. It would also attach obligations to service provision (e.g. by activity or service) instead of asset-based obligations.

The workstream will review the consumer protections framework to make sure consumers retain sufficient and appropriate levels of protection in an evolving market over all timeframes.

Potential options and indicative timelines and sequencing being considered are outlined below. This summary is not intended to be exhaustive nor definitive, and the ESB will continue to engage with stakeholders and interested parties on the evolution of each of these elements. As the market frameworks continue to adapt, each aspect of the move to a two-sided market will be considered in more detail to understand how options would operate and ‘fit’ with arrangements in place at the time, to ensure they are fit for purpose throughout.

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<sup>52</sup> <https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/pilots-and-trials/demand-response-trials> and <https://arena.gov.au/news/aemo-arena-demand-response/>



## Short term (now to two years)

### Participation frameworks:

- An expanded aggregator framework that would allow for easier aggregation of DER for participation in energy and FCAS markets.
- Consider the appropriate treatment of technical requirements for participating in central dispatch and forecasting processes and market interface requirements, e.g. the telemetry and communications requirements.
- Consider changes to the NEM to better integrate storage devices through a rule change request submitted to the AEMC by AEMO.<sup>53</sup> The AEMC has also received a rule change request from the AEC proposing changes to the generator registration thresholds. In considering the AEC's proposal, the AEMC will be assessing the participation frameworks for different generator sizes.<sup>54</sup>

### Scheduling, pricing, dispatch and forecasting:

- Use experience with VPPs providing operational forecasts to the market operator and consider how this could be expanded.
- Activities to improve visibility – AEMO's ST PASA replacement project involves a comprehensive review of the PD and ST PASA methodology, exploring the development of a system that will serve the NEM now, and into the future. A review of the methodology and guidelines for demand-side participation in the NEM is also underway.

## Intermediate term (two to five years)

### Participation frameworks:

- Explore ways to simplify the regulatory arrangements related to registration and classification, and provide a level playing field for entry to the market across traders who provide a range of services. A less complex registration process would make it easier for new traders to enter the market and for existing traders to provide new services. This framework would also lead to increased customer choice regarding the degree of interaction with the wholesale market, including increased choice of service providers in relation to different services the customer can receive from, or provide to, the market.
- Make it easier for traders to enter the market and provide different types of services, including greater consideration of how to attach certain obligations to service provision instead of asset-based obligations.

### Scheduling, pricing, dispatch and forecasting:

- Develop and establish mechanisms to remove barriers and incentivise traders to aggregate supply and demand to participate in dispatch on a level playing field. This may include evolving obligations for scheduling in a 'lite' manner (that is, a set of scheduling obligations that make it easier for currently non-scheduled participants to participate in central dispatch, while still maintaining the integrity of central dispatch); enabling co-optimisation of service provision with other new essential system services; and enabling traders to voluntarily take a position in an ahead market if it is available.
- A revised set of scheduling obligations and incentives that lower the barriers to currently non-scheduled participants becoming scheduled and encourage greater participation in central dispatch.

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<sup>53</sup> On the AEMC's website: <https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem>

<sup>54</sup> On the AEMC's website: <https://www.aemc.gov.au/rule-changes/generator-registration-thresholds>

- Explore how price signals and a cost for congestion can be made increasingly available to provide investment and participation signals to end users who can provide local, network or wholesale market services.
- Set up mechanisms to allow operational forecasts to be provided by traders to assist with demand forecasts. These forecasts will improve the effectiveness of short-term forecast outcomes and improve dispatch outcomes.

### Longer term (five years and beyond)

#### Participation frameworks:

- Participation frameworks that are flexible and easily accessible. This could include removing the generator supply/consumer demand separation that is outdated and presents a barrier to traders, including aggregators, participating in the market with a combination of load, generation and storage assets and where connection point flows are increasingly bi-directional. This change would be undertaken following further consideration of the implications of making such a change, including the impact on existing participants.

#### Scheduling, pricing, dispatch and forecasting

- Further consideration of how best to enable price responsive injections and withdrawals to participate actively in the market including a voluntarily participation in ahead markets for energy, RAMs and ESS such as operating reserves and fast frequency response markets.
- The goal will be to transition to a market where any material quantities of supply or demand that are either price-responsive or variable would be actively involved in central dispatch. This would involve considering the most appropriate set of incentives and obligations on the parties actively participating.

#### *Consumer protections and complementary measures*

- Appropriate and fit-for-purpose consumer protections will need to be in place throughout the transition period.
- Recommendations on an approach to energy-specific consumer protections that would apply under a two-sided market. This will be progressively developed as the design for the two-sided market design develops, building on and evolving existing consumer protections to ensure they are fit for purpose and adaptable to new services.
- Consider where other complementary measures may also be appropriate to support improving outcomes to consumers who may not have the means, ability or motivation to engage in new market offerings. Using complementary non-financial measures, there is potential to increase the proportion of consumers that may be able to engage in new two-sided market offerings, increasing value to those consumers directly, as well as reducing uncertainty and improving outcomes for all consumers at a system level.
- Principles and assessment criteria will be developed as the market design moves through the stages of implementation to enable any emerging risks or unintended consequences to be considered as new products and services emerge.

### 8.3. Questions for stakeholders

1. What do you consider are the risks and opportunities of moving to a market with a significantly more active demand side over time? How can these risks be best managed?
2. What are the barriers preventing more active demand response and participation in a two-sided market? What are the barriers to participating in the wholesale central dispatch processes?
3. Do you think any other near term arrangements or changes to the market design can be explored in this workstream?
4. What measures should be deployed to drive consumer participation and engagement in two-sided market offerings, and what consumer protection frameworks should complement the design?
5. What might principles or assessment criteria contain to help assess whether it is timely and appropriate to progress through to more sophisticated levels of the arrangements?
6. The ESB is considering combining the DER integration (below) and two-sided markets workstreams, or elements thereof. Do stakeholders have suggestions on how this should be done?

## 9. VALUING DEMAND FLEXIBILITY AND INTEGRATING DER – MARKET DESIGN INITIATIVE F

### Key points

The rapid increase of DER on the NEM, at both household and grid scale, presents a range of opportunities and challenges that require a holistic approach to ensure effective system and market integration, and to unlock benefits to all energy system users. Effective integration of DER has implications across the post-2025 market reforms and will be considered as a key interdependency for each workstream.

A broad program of work is underway and being coordinated by the ESB to support this: including initiatives considering changes to technical, regulatory and market settings. The focus of the market integration is expected to occur in three overlapping stages:

- Foundational measures (including considerations for changing the market design for DER integration),
- Facilitated participation (including defining participation requirements to enable DER to participate multiple markets)
- Deep market integration of DER (including realising opportunities for DER to participate in multiple markets and service provision (value stack) where it is efficient and technically viable to do so).

Six key considerations for DER integration need to be addressed in developing a post-2025 market:

1. The balance of how DER services are delivered – through markets and/or technical and regulatory processes.
2. How responsive DER and engaged & willing DER owners will be to participate in markets.
3. The infrastructure required for DER participation, especially operating envelopes.
4. Definitions of aggregators to support DER participation and compliance under post-2025 market designs.
5. The balance between participation and full market integration of DER services.
6. The potential for distribution-level markets.

The ESB invites feedback on these considerations and the priorities for DER integration going forward.

This program of work dovetails with the two-sided market workstream and aims to ensure that DER can participate markets across all aspects of the NEM. How the two workstreams are structured going forward will be considered further by the ESB.

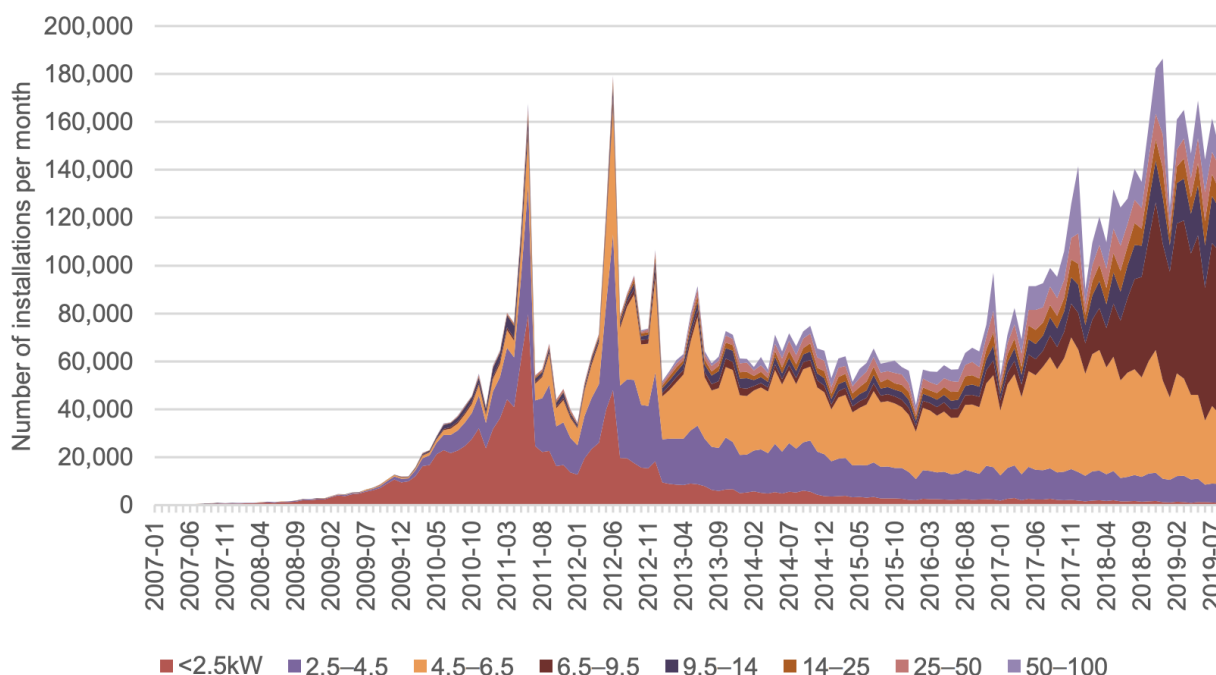
### 9.1. What is the problem this initiative is addressing?

DER are a rapidly growing presence in the NEM. DER include a broad cross section of technology, for example solar PV, batteries, EVs and controllable air conditioning units. The technology is constantly evolving, driven by consumer choice and equipment and technology innovation, while the cost of technology continues to reduce.

The growth in rooftop solar and related battery storage in the NEM, over the period 2007 to 2019, is shown in Figure 31 below. Much of this growth has been driven by government subsidy schemes and consumers trying to reduce their electricity costs and emissions. The uptake in

batteries is less dramatic than the uptake in solar PV, but as Figure 31 shows, battery uptake has started to increase in recent years.

FIGURE 31 SMALL SCALE SOLAR INSTALLATIONS BY SIZE IN kW SINCE JAN 2007



Source: ESB, Health of the NEM 2019

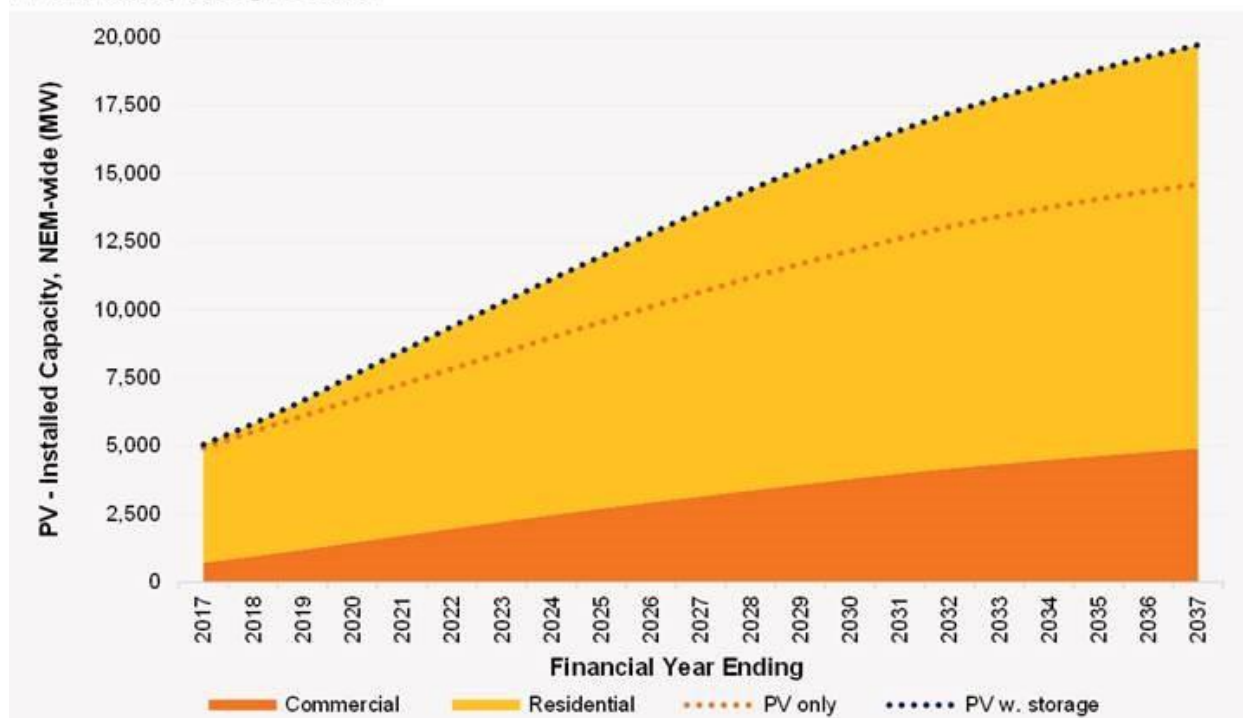
It is anticipated that growth in DER, both volume and type, will gather pace (see Figure 32), with new technologies, new business models and an increasing diversity of consumer expectations facilitating increasing diversity of services. This in turn will create increasing opportunity for new services and technologies to be integrated into the overall system to maximise their benefits and deliver outcomes consumers want, such as lower prices, improved reliability and low emission electricity. In planning for this future, it will be necessary for the regulatory arrangements to be flexible to accommodate this scale and pace of change.

By 2030, AEMO expects approximately 50% of consumers in the NEM to use some form of DER (solar PV, controllable load, storage, EVs, or a combination). The 2020 ISP projects investment in a further 10,926 MW of distributed solar generation by 2040 in the central case and double that on the high DER case.<sup>55</sup>

At a whole system level, the impact of DER in the NEM is significant. In Section 2 the operational demand for energy in South Australia was discussed briefly and depicted in Figure 9. The infamous ‘duck curve’ shows demand for power can be zero or less in the middle of the day. This effect is already evident in some Australian cities where the take-up of DER is high: Adelaide, Brisbane and Perth. In these locations the distribution companies and the system operator are facing a challenge to keep generation and demand in balance and the system stability within its technical envelope. It is not that the problems cannot be overcome, as the devices that are being installed have increasing flexibility. However, the regulatory and market design must change to enable sufficient incentives and safeguards to be addressed effectively.

<sup>55</sup> <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp>

FIGURE 32 SOLAR PV AND BATTERY STORAGE FORECAST  
PV and battery storage forecast



Source: AEMO

Effective integration of DER is important for the system and also to ensure the value of these resources can be used effectively for the benefit of all energy system users. The highest immediate value use of a consumer's DER is typically on-site, avoiding electricity consumption charges. If excess generation or demand response capacity is available further additional value can be created through appropriate market design and procurement mechanisms.

As discussed in Section 8, DER can provide services across the whole of the electricity system – from generation, to transmission, to distribution and within the customer's premises. DER are already participating in energy markets, and Section 6 discusses how DER can play a role in delivery of system services and network support markets. However, at present there are only limited arrangements for owners of DER to offer services into these markets. This means the potential benefits of optimal market integration are foregone. It also means that future investments in DER are unlikely to be optimal. This disadvantages both owners of DER and other consumers on the system.

## 9.2. What are the options considered?

### Staging the approach

There are technical requirements to ensure security and reliability in system with high levels of exports and imports from DER. This workstream is considering the role markets can play in facilitating the affordable, secure and reliable supply of energy for all consumers, while facilitating consumer preferences as to how they engage with energy markets. The critical path to DER integration within the post-2025 market design is in three stages:

#### 1. Foundational measures.

- Enhancements to DER visibility, communications, standards and interoperability.



- Identification of key considerations in changing the market design for DER integration in changing the market design in the post-2025 program (currently under consultation).
- Pilot DER for participation in network services, wholesale markets, FCAS/ESS and via local markets (currently underway).
- Design options and market architecture in consultation with stakeholders.

## 2. Facilitated participation of DER.

- Define aggregators and market participants to facilitate consumers' participation in wholesale markets and the provision of network services (to be carried out in conjunction with the two-sided market workstream).
- As the post-2025 market design progresses, develop more opportunities for participation by consumers with DER across multiple markets including in the two-sided market, ESS and ahead markets.
- Continue to pilot market design options for DER participation in network services, wholesale, FCAS/ESS and via local markets.
- Investigate behavioural dimensions/non-financial motivations of consumers for DER.

## 3. Deep market integration of DER.

- Finalise opportunities for DER to participate in all markets where it is technically possible and efficient to do so.
- Realise the opportunities for DER to participate in multiple markets and service provision (value stack) where efficient to do so.
- Design of options and market architecture in consultation with stakeholders and move toward the optimal integration of DER, across wholesale and distribution level and co-optimising between the different potential services DER could competitively provide.

## Work in progress or completed

A range of technical and regulatory reforms are being pursued by the AEMC, AEMO and the AER, and a number have been completed. In addition, numerous trials and studies are being conducted by distribution businesses, AEMO and others in partnership with universities and industry. Many of these trials have been part-funded by ARENA under its Distributed Energy Integration Program (DEIP). This work is at the frontier of development, given the world leading penetration of DER in Australia. The ESB has developed a DER Integration workplan, which sets out in further detail the technical, regulatory and market related actions underway across the energy market bodies.<sup>56</sup>

Work to date has focused on building technical and regulatory foundations to support effective integration, including the following:

- The DER register went live on 1 March 2020.
- The ESB and market bodies are progressing arrangements to have initial technical standards for DER in the NEM which will build on the draft inverter standard AS4777.2 with ride through capability. This will particularly assist solar and battery systems to ride through voltage and frequency disturbances in the grid.
- The ESB has commenced a governance process for ongoing development of technical standards.

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<sup>56</sup> <http://coagenergycouncil.gov.au/energy-security-board/distributed-energy-resources>

- Voltage issues on the low voltage network have been investigated. The ESB commissioned a report from the University of New South Wales which found rooftop PV makes only a small contribution to already high voltage levels.
- Operating envelope trials underway – several trials of software to provide dynamic upper and lower bounds for DER exports within DNSP technical requirements are underway, most part-funded by ARENA.
- In June, the AEMC released a final determination setting out a series of changes to the National Electricity Rules to facilitate wholesale demand response in the NEM.
- The AEMC has completed its review updating the regulatory framework for distributor-led standalone power systems. The review developed detailed revisions to the rule to enable implementation of distributor-led standalone power systems.
- AER has a project underway to consider the Value of DER (VaDER) for regulatory purposes, with a report due to be released in October 2020. Following the VaDER study, the AER will be developing a guideline for the assessment of proposed investment in DER by distribution NSPs (DNSPs).
- Rule change requests submitted as part of the DEIP Access and Pricing Work Package cover matters including DNSPs responsibilities for DER integration and pricing of DER distribution access and pricing issues and reform options integration and export.

It is also important to note that some DNSPs have already commenced substantial work to facilitate DER integration. Work in this area includes business cases and/or regulatory proposals to improve low voltage network visibility, continual implementation of network tariff reform, and new systems such as development of dynamic operating envelopes.

### Coordinating DER integration with other market design initiatives

Co-ordination of DER integration within the other post-2025 market design initiatives outlined in this paper is critical. We outline below six key considerations that will enable this coordination to occur and ensure that DER can be fully integrated across all other Post-2025 workstreams, particularly two-sided markets, essential system services and scheduling and ahead markets and eventually into all aspects of the electricity market.<sup>57</sup>

#### Consideration 1: How DER services are delivered – through markets and/or technical and regulatory processes

The first consideration relates to the relationship between the provision of DER services in response to price signals compared with their delivery via technical and/or regulatory ‘off market’ capabilities.

The technical capabilities of DER have advanced significantly over the last few years and are continuing to do so. This means DER is readily able to respond to external signals (both price signals and potentially via direct control). However, these advancing capabilities may also reduce the need for related (emerging) market services or control mechanisms. For example, advanced inverters can provide dynamic voltage control (either independently or through operational envelopes) and frequency control. This may provide alternatives in addition to the services offered in the ESS markets. Enhanced technical capabilities can also increase the visibility of DER and consumer loads, reducing uncertainty relating to demand forecasts by improving situational awareness in real time. It is possible that regulatory measures to set effective import and export limits to the customer connection (requirements for operating envelopes) can be used to help address the problem of minimum demand at the wholesale level.

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<sup>57</sup> ESB commissioned advice from ITP/KPMG that informed this thinking.

Challenges arise from the need to address multiple outcomes, i.e. engineering or regulating for DER functionality and creating markets to stimulate DER service provision. For example, provision of power quality services through technical standards reduces the size of the market for these services and can crowd out market players such as aggregators – who are then left to service the residue.

The technical or regulatory provision of power quality services can also reduce NEM-wide system costs, which raises the question of whether these DER owners should be financially compensated for any such services. For residential DER owners, the loss of revenue can be very small (likely tens of dollars per year) so the cost of administering the compensation may be more than the compensation amount.

Deliberate consideration into the appropriate balance between whether market solutions or technical standards or regulation represent the best outcomes for consumers is required. It will be important to understand consumers' preferences for use of their assets in various scenarios for technical, regulatory and market-based service provision.

*The ESB and market bodies will undertake work to understand (and where necessary quantify) the trade-offs between technical and regulatory delivery of the various DER services and the value in creating markets to deliver these services.*

## Consideration 2: The forecast for responsive DER and willing DER owners

For DER to be able to actively participate in the market design, they will need to have the hardware, communications and software capability to respond. It will need to be in some way 'active', compared with the passive rooftop solar PV systems which currently dominate DER generation.

Batteries and EVs have the capability to actively respond to market signals, and while technological progress is unpredictable, there is potential for enhanced vehicle-to-grid capability to cause a step change in responsive DER. Progress in implementing more cost-reflective tariffs and pricing will deliver better signals to consumers and lead to improved generation and load responses.

Implementation of market reforms, such as two-sided markets, may increase an uptake in DER that chooses to participate in the associated markets. Other forms of DER can also participate in future markets, such as air-conditioners, water heating, and pool pumps.<sup>58</sup>

The ability and motivation of DER owners to engage in energy markets is also relevant. The highest value use of DER is almost inevitably on-site to reduce electricity bills. Consumers therefore need to have spare capacity and be able and willing to engage with retailers, aggregators or service providers. Initially, this could be a small market, but it is expected to increase with greater uptake of DER over time. There may also be particular transition points, for example where batteries and EVs hit a mass take-up price point, as occurred for solar PV. Alternatively, new models for bundled DER services may also prove attractive to consumers, e.g. EV leasing, PV for landlords, and other innovative DER services may rapidly increase DER adoption.

*The post-2025 market design project will review DER forecasts and model the likely uptake of different types of DER, their technical characteristics and consumer willingness to participate in external markets.*

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<sup>58</sup> These other DER could be more suitable for reducing demand during high spot prices, reducing minimum demand risk, and during network demand peaks and other local distribution level value streams for DER.

### Consideration 3: The infrastructure required for DER participation

Effective integration and optimisation of DER requires a substantial increase in data and sophistication, and therefore an expansion of communications infrastructure. The interactions involving DER at different levels in the electricity system are outlined in Figure 33<sup>59</sup>.

FIGURE 33 OVERVIEW OF DER INTERACTIONS AND SUPPORTING ARCHITECTURE ALONG THE SUPPLY CHAIN

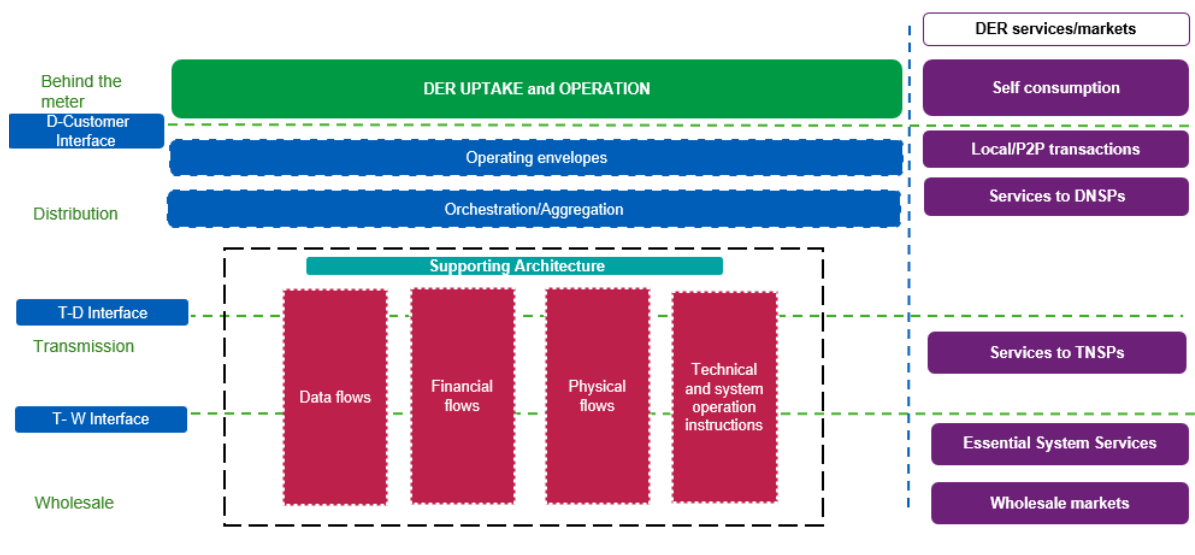


Figure 33 illustrates the potential supporting markets arrangements and architecture required to optimise DER value streams (from self-consumption through to wholesale markets) for the NEM. It shows that the supporting architecture must manage data, physical and financial flows - a substantial increase in data flows and sophistication, and therefore an expansion of IT and communications infrastructure:

- For consumers, this infrastructure includes DER communications systems, including internet connections.
- For aggregators, communications infrastructure includes servers and systems such as platforms for data acquisition and control across a very large numbers of consumers, interfaces with the DNSP's systems and interfaces with the market operator.
- For DNSPs, existing Distribution Management Systems (DMS) will need to be expanded with added capabilities to allow efficient network operations with the presence of DER, and facilitate interactions with aggregators.
- For AEMO, a future market characterised by high DER participation will require a smooth interface with system and market operations.

The challenge of upgrading, integrating, and efficiently and securely operating all of these different components is significant. Standardisation of this infrastructure and communications will be necessary in many areas to reduce overall costs. Cybersecurity considerations will also need to be a key input at each step of the design process. There are a number of initiatives underway to assist in more efficient design, management and integration of DER dataflows across these assets, and each are steps towards convergent system design. The potential significant costs to consumers in developing this infrastructure needs to be understood.

<sup>59</sup> Created by ITP and KPMG for the ESB

*The ESB and market bodies will consider and take these infrastructure costs into account and seek to balance costs with benefits when designing DER participation arrangements.*

#### Consideration 4: Definitions to support DER participation and compliance under Post-2025 market designs

For aggregators to maximise the value of their DER portfolio, they need to access multiple revenue streams across multiple markets – known as value stacking. As discussed in Section 8, definitions of aggregators and market participants will need to be reviewed and refined to support delivery of a range of services by different providers.

A core feature of any market design is the rules regarding eligibility to participate, calculation of payments and compliance. In considering these issues, the principle of technology neutrality is relevant, as is the principle that the owner or aggregator providing the services must be able to meet its commitments under any market or else face penalties.

This is a challenging balancing act. The market design must provide for non-discriminatory participation by qualified participants and the outcomes must be observable and be able to be verifiable. At the same time, the technical, communication and commercial characteristics of different types of DER should be used to determine whether the arrangements need to be adapted to facilitate DER participation (e.g. should equivalent performance obligations that exist on large generating plant also apply at the individual DER level?). These considerations become more challenging when consumers may in future have many different types of DER assets in their homes or businesses.

If participation rules for DER are too onerous or costly to comply with, then there is a risk the expected uptake of DER will not effectively integrate into the market. This is not a reason to treat DER materially differently to other resources, but instead creates a need to learn from trials to better understand how to define the criteria and arrangements.<sup>60</sup>

A challenge in this area is to ensure that any new arrangements are capable of encouraging sufficient level of consumer involvement – noting that it is not necessary for all DER owners to participate for benefits to be realised. An important part of this is building a better understanding of consumer behaviour.

*The roles, capabilities and obligations of aggregators and Market Participants will be reviewed to increase flexibility to offer DER services that could drive value for consumers. These participant categories will be co-designed with the Two-Sided Markets work.*

#### Consideration 5: The balance between participation and full market integration of DER services

DER could potentially provide, and receive revenue for, many services in multiple areas:

- Network services – use of DER to substitute for capex or opex, including to improve network utilisation and for power quality management.
- Wholesale energy/demand response – through local trading (yet to be developed), current wholesale and demand response markets, future two sided-market, ahead markets.
- Essential system services – for example, frequency, black start – for current and future markets, possible ahead markets.

In this way, either as a single asset/facility or as a virtual resource formed as an aggregation of individual sub-resources, DER can provide multiple services to several entities with

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<sup>60</sup> AEMO's sampling approach to VPP capability in the current trials is one example of answering these challenges. AEMO requires the VPP operator to use a reference or sampling meter to provide 50 ms data for a selection of sites rather than for all sites.

compensation received through different revenue streams.<sup>61</sup> For DER to deliver value across the range of services, it is important to ensure consistency and alignment of financial incentives – the nature and design of the price signal or compensation payment – for the value generated by DER services.

Considerations include:

- Removing barriers through enabling consumers to have relationships with several parties and ease of market participation for third parties.
- Different design impacts on DER participation both from the consumer and aggregator perspectives.
- How collectively all the different price signals under the various markets would work together and reinforce each other in a manner which promotes market efficiency.

Efficient DER integration is more likely to emerge if there is common agreement on how to calculate the value from different DER types. The AER's DER expenditure guideline is intended to support a more consistent identification of the value DER can provide to all consumers. This Guideline should support improved consistency in the valuing of DER services and the efficient augmentation of the electricity grid to release this value. Consistency in systems will enable aggregators to more easily spread resources across multiple markets – ensuring that it is offered in a way that best meets both system and consumer needs.

To support effective market design, it will be important to allow flexibility and fungibility of service provisions between markets, allowing a large pool of DER to compete for a wide range of services with as little barrier to participation and service provision as can be justified from a network and system security perspective.

*The post-2025 market design will ensure that DER owners and aggregators have opportunities to participate in the provision of a range of services to wholesale markets and networks where it is economically efficient.*

While DER owners and aggregators should have choices to participate in the provision of services, this is a careful 'balancing act'. It is a balance between the DER service provider meeting its own expectations and providing services to the market at a given point in time. There may be times where servicing the DER owner's need would take priority. Beyond alignment on financial incentives, to maximise the mix of services a DER provider supplies at any time, arrangements will need to support effective competition and co-optimisation of DER services. Co-optimisation by the DER owner would be the ability to select how best to deploy the DER resources to maximise revenue and enable DER owner preferences – so that the DER facility/owner has the ability to 'shop around' and evaluate the various revenue options. Co-optimisation from a system perspective would allow DER owners to offer all their capacity into every market at once at difference prices and allow a central clearing engine to choose the most efficient use of that capacity. This is likely to mean different uses for DER at different times of the day and year. Effective co-optimisation should:

- Lower system costs as existing capabilities are better deployed.
- Better enable integration with the market as the DER customer receives more value from its facility.
- Increase the uptake of DER as increased returns make DER more economical.

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<sup>61</sup> VPP trials that currently provide value behind the meter as well as into spot and/or FCAS markets are a tangible example.



- Decrease the likelihood of load and grid defection as consumers see more value in staying connected and in contributing to the system.

However, co-optimisation could be very difficult to achieve in practice, and will depend on:

1. The regulations and contractual arrangements underpinning the various compensation channels,
2. The congruency of the financial incentives.
3. Consumers' willingness and understanding.
4. Information flows to enable accurate and timely evaluation of trade-offs.
5. Investment in IT systems and communications, including cybersecurity, to enable co-optimisation at the customer level.

Provided DER owners and aggregators have opportunities to participate and good information, they have the opportunity to undertake their own optimisation, albeit with some limitations. The complexity and potential cost of co-optimisation then needs to be balanced by the additional benefits it can deliver when deciding how far the DER market design should move from supporting participation to delivering full integration and co-optimisation.

#### *The balance between self-optimisation and system operator optimisation*

Self-optimisation refers to the DER owner (or its agent, such as an aggregator) considering how to solve and deploy its DER resources for its own benefit. System operator (SO) optimisation is when the system operator/dispatch processes decides how best to deploy the capability across the multiple markets in each time interval with a view to provide optimal benefits to the whole system.<sup>62</sup>

These two approaches are not mutually exclusive, and there is likely to be a combination of both approaches. There are many considerations to design the most appropriate arrangements that support self-optimisation while involving the SO where it supports greater value delivery. For example, DER could be compensated under the Wholesale Demand Response Mechanism (WDRM) and at the same time contribute to alleviating a local network constraint.

There may be a need for some regulatory or centralised framework for aligning multiple revenue streams to avoid potential free-riding and DER value leakages. This is a challenging issue of balancing the costs and inflexibility of regulatory solutions versus addressing market and commercial barriers.

In a two-sided market, the trader (e.g. retailer or aggregator) would be responsible for co-optimisation of the value stack and submitting bids for a range of services. It may need to value-stack those services and revenue streams to be financially viable. This in turn means it will need to service a diverse range of end users by accounting for the preferences and capabilities of those end users. The aggregator may do this by packaging a single service offer.

This will be an extremely complex real-time co-optimisation challenge, requiring careful market and regulatory design such as appropriate regulatory arrangements that allow/enable an aggregator to participate in multiple markets.

#### *Customer issues for co-optimisation*

A consumer interested in participating in one or more external markets could end up with a very complicated stack of options requiring sophisticated DER with multiple devices and telecommunications required to receive different price signals and then respond to one of them in each time interval. Prior to getting to this point, they will face their own co-optimisation problem:

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<sup>62</sup> This is as currently occurs where NEMDE co-optimises energy and FCAS for large-scale generators.

having to choose between a range of different offers from different providers, making a series of value judgements regarding upfront costs versus potential future revenue streams.

Avoiding adverse consumer outcomes will require:

- Consumer protections against unscrupulous and monopolistic behaviours, especially those that could result in disadvantageous technology lock-in.
- Access to reliable information to be able to determine the value of their DER and the services it can provide.
- Clear information to support informed decisions (e.g. similar to online calculators such as the Energy Made Easy website).

#### *The role of the distribution networks in enabling co-optimisation*

To facilitate co-optimisation, DNSPs will need to develop the following capabilities:

- Significantly improved visibility of networks in real time, including the capacity to model and forecast that capacity under different scenarios (e.g. 24 hours in advance on a rolling basis).
- The ability to deploy a real-time operating envelope<sup>63</sup> that will automatically limit all participating imports and exports on the network to within limits consistent with power quality standards.
- In the future, there may also be the possibility of trading excess network capacity between consumers or incorporating economic considerations into operating envelope calculations.

The use of DER to provide network support services is a further consideration. This being optimal will depend on:

- The DNSP providing clarity to the DER owner as to when and how often the network support services are likely to be required, and the value of that service, so the consumer can make an informed choice about participating.
- Clear terms and conditions, including financial penalties for non-compliance, which could be loss of anticipated income as opposed to penalties.
- How the DNSP translates its obligations to maintain a reliable, safe and secure network in access and connection arrangements for DER.
- A mechanism that places incentives on DNSPs to ensure hosting capacity is optimised to allow consumers and their DER to participate in the wholesale and ESS markets and the marginal costs of extra hosting capacity are fairly apportioned.

These last two points are currently being examined in a series of distribution 'access and pricing' rule changes being examined on currently by the AEMC.

*The post-2025 market design will consider the steps, costs and benefits of moving from partial participation to efficient co-optimisation of DER services.*

#### **Consideration 6: The potential for distribution-level markets**

For the purpose of this consultation paper, distribution-level markets cover transactions at the local level (where buyers and sellers are located on the same distribution network). It could include local energy trading between consumers or between a community battery and other consumers and nested wholesale markets where optimisation occurs at a local level prior to interaction with the whole of system market.

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<sup>63</sup> SA Power Networks (SAPN) is currently applying a 5-minute operating envelope to Tesla's VPP.

A key issue for post-2025 is the extent to which there will or should be local settlement of transactions outside the wholesale markets.

Distribution-level markets may be warranted at some time in the future. The ESB will investigate the potential role for such markets and seek to determine the threshold conditions under which they should be implemented.

### 9.3. Which options are proposed for further development and consideration?

The priority for the Post-2025 program is to integrate DER into the considerations for market design. This includes:

- Setting up the necessary foundations for the participation of DER in terms of technical and regulatory arrangements and understanding the infrastructure requirements (which will be largely undertaken through the DER integration workplan).
- Ensuring opportunities for DER to participate are in place where it is efficient. Define aggregators and market participants to bring new actors into the post-2025 market design through co-design with the two-sided markets workstream.
- Developing participation requirements, compliance and enforcement arrangements that make it simple for DER to provide services into all markets, and simple for DER owners.
- Developing overarching market design options which enabling value-stacking for consumers with DER and explore the need for full integration into markets.

### 9.4. Questions for stakeholders

1. Have any key considerations for the incorporation of DER into the market design not been covered here? For DER to participate in markets, it needs to be responsive. How should the Post-2025 project be thinking about enabling responsive DER?
2. In the next phase of the project, the ESB proposes focusing on development of a detailed DER market integration proposal. What are the most important priorities for DER market integration? We are considering combining the DER integration and two-sided markets workstreams, or elements thereof. Do stakeholders have suggestions on how this should be done?
3. How can we ensure owners of DER can optimise the benefits of their DER assets over time as technology and markets evolve? How do we time reforms to manage the costs and benefits for DER owners?

## 10. TRANSMISSION ACCESS AND THE COORDINATION OF GENERATION AND TRANSMISSION – MARKET DESIGN INITIATIVE G

### Key points

Over the next 20 years, there is a need for large quantities of renewable generation and energy storage to connect to the power system. There is insufficient transmission network capacity in the right locations to support this forecast generation, and there are limited price signals to encourage generators where to locate.

Accommodating new generation and storage within the grid is already posing difficulties associated with network congestion, low marginal loss factors (MLFs) and technical challenges. Going forward, congestion is forecast to increase.

To address these challenges, a number of reforms are already underway or have recently been implemented (including reforms to make AEMO's ISP actionable). As a short term measure, the ESB is developing interim arrangements to support development of several REZs. For the longer term, there is a need for transmission access reform to improve locational signals to generators and efficiently manage congestion.

The AEMC is developing a model for transmission access reform with two core elements:

- Locational marginal pricing (LMP) – scheduled market participants would receive/pay a price that would more accurately reflect the value of supplying electricity at each location in the network and make the physical elements of the system more transparent.
- Financial transmission rights (FTRs) – these would allow participants to manage the risks of congestion by allowing them to purchase an FTR which would pay out on the differences in wholesale market prices arising due to congestion.

Reforms are intended to support efficient and timely capital investment, efficient system operation and reduce costs to consumers. Independent modelling undertaken by NERA Economic Consulting for the AEMC has developed an initial estimate of the benefits of introducing locational marginal prices over the next 20 years. The ESB and AEMC are interested in stakeholder views on the modelling and assumptions used.

### 10.1. What is the problem this initiative is addressing?

#### The existing grid and transmission access frameworks are not built for the generation of the future

As discussed in Section 2, the transmission network in the NEM was primarily designed and built in a time when generation to supply consumers' needs was different to that now and in the future – both in nature and in location. Unlike the existing power system, the system of the future is likely to be characterised by many relatively small and geographically dispersed supply sources to meet system needs. Most new generators are unlikely to be located where there is substantial existing transmission to serve them, because they have different energy sources compared to the existing generation fleet and are being connected in sunny or windy areas, where the network is thin and capacity is limited. Basically, the transmission grid needs to be reconfigured to accommodate the changing resource mix.

To meet future needs we expect to have to accommodate:

- More variable, renewable generation with lower average capacity factors than conventional generators, and in different locations.
- More storage, both from pumped hydro and batteries.

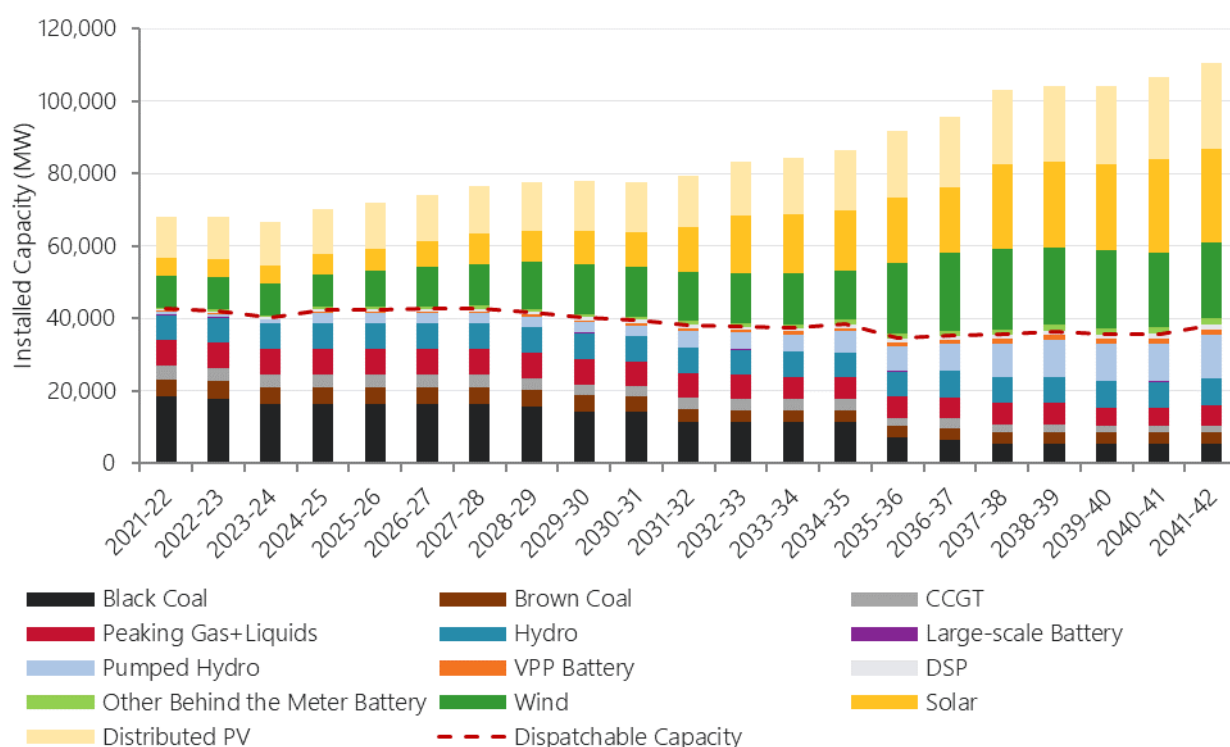
- More distributed generation and storage.
- Emerging issues of system strength and voltage instability.

The nameplate capacity of generation and storage in the power system is expected to grow dramatically to 2040. The Central scenario in the 2020 ISP<sup>64</sup> projects that by 2040 there will be:

- An additional 31,140 MW of variable renewable generation connected to the transmission system.
- An additional 11,737 MW of storage.

Figure 34 below clearly shows this forecast decline in thermal generation and increase in hydro, large scale wind, solar, distributed resources and storage.

FIGURE 34 INSTALLED CAPACITY BY YEAR (ISP CENTRAL SCENARIO)



Source: AEMO, 2020 Integrated System Plan

To deal with this unprecedented change, the 2020 ISP sets out proposed augmentations of the transmission system to support connection of the capacity that is projected to occur. This ISP analysis is based on a whole system optimisation to deliver a network that is efficient (with some congestion) rather than completely uncongested, and the scale of new transmission investment is driven by the scale of investment in generation and storage shown in Figure 34.

Looking at the actionable ISP projects in the 2020 ISP, EnergyConnect has a rated transfer capacity of 800MW, HumeLink 2230-2570MW and VNI Minor 170MW, while Central-West Orana REZ Transmission Link will have generation hosting capacity of 3000MW.<sup>65</sup>

<sup>64</sup> <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp>

<sup>65</sup> The ISP also identifies two projects as actionable subject to decision rules: VNI West (1930MW) and Marinus Link (750MW). Early works are to commence for these projects, with the decision rules to be assessed during the Regulatory Investment Test – Transmission (RIT-T) and confirmed by AEMO as part of the ISP feedback loop process.

The transmission investment needed out to 2040 in the ISP optimal development path is around \$23 billion in 2019 dollars<sup>66</sup>, and routes and easements are not yet planned or finalised in many cases. Ensuring that these major projects remain on time and in budget once regulatory and planning approvals have been granted is a significant challenge. It is many years since the transmission companies have built major interconnectors and managed projects of this magnitude. Delivering on time and within budget is necessary for connection of the new generation and storage fleet to meet customer needs at the lowest cost within current policy settings.<sup>67</sup>

## Congestion and access

Accommodating this new generation and storage within the grid is already posing difficulties. Increases in generation being connected in areas with relatively weak transmission links has caused reductions in MLFs, rising congestion, and difficulties meeting technical requirements.

Congestion occurs when elements or sections of the network reach a technical limit. When congestion occurs and forms binding system constraints, the cheapest available power cannot be dispatched. Demand must still be met, and the power required must come via some alternative route and more expensive supply. Congestion displaces the cheaper generation with an unconstrained resource (to the benefit of more expensive generation) to make sure the system remains within its physical limits.

In practice, this means consumers are not getting the benefits of cheaper generation. When congestion arises on the transmission network and transmission constraints bind, the underlying value to consumers of an additional unit of electricity differs from location to location. Without investing in more transmission capacity, which takes time and expense, the amount of electricity flowing out of the congested area cannot increase, due to the limit being reached on the element or network section. Therefore, the value of electricity in congested parts of the network is typically relatively low; additional generation in that area can only offset the most expensive generator which is also in the congested area.

In some congested areas, and at some times, all the generators that are operating may be variable renewable generators, so the incremental value of additional variable renewable generation is close to zero; the next renewable generator simply reduces the output of the existing renewable generators. In contrast, additional renewable generation in an uncongested area offsets the most expensive generator anywhere and its incremental value is higher. While variable renewable generators have close to zero marginal cost, having better signals about where their location should be results in more efficient investment and operation.

The cost of alleviating congestion – building transmission infrastructure – can exceed the cost of the congestion occurring itself. For this reason, the optimal level of congestion is not zero. There is a balance between the cost of augmenting the network and the costs of congestion which AEMO, TNSPs and the AER must consider in the planning process.

Reflecting this trade off, congestion is reasonably common. There are many instances of congestion every year, and, not surprisingly with the changes occurring in the NEM, the level of congestion has increased substantially in recent years where there have been large increases in new generation in areas with relatively weak transmission capacity. This is particularly notable in North Queensland, South West New South Wales and North West Victoria.

Projections show these trends continuing. Congestion would ideally be measured by its cost, but this is difficult in the NEM because of its regional structure and the related bidding behaviour.

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<sup>66</sup> Derived from AEMO, 2020 ISP, Table 14 (modelled costs)

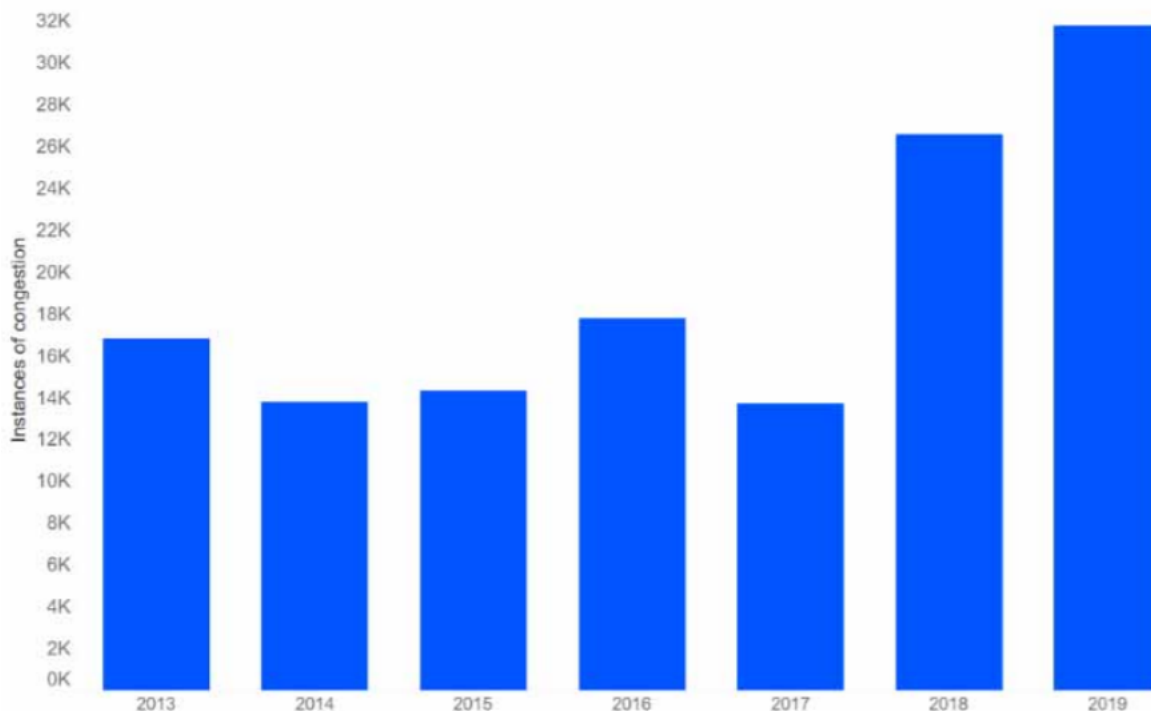
<sup>67</sup> The AEMC is currently considering these issues through its Electricity Network Economic Regulatory Framework Review (ENERF).



Figure 35 below shows the growing congestion in the NEM measured as the number of individual elements or sections of the network that are congested in any five-minute period.

AEMO (and TNSPs) through their planning processes are forecasting significant increases in congestion across the entire network, driven by the substantial levels of investment in new generation.<sup>68</sup> The changes in national planning in the NEM, coupled with changes to the transmission access arrangements, ensure that transmission can be developed and then fully utilised with appropriate incentives and risk management arrangements.

FIGURE 35 INSTANCES OF CONGESTION IN THE NEM 2013-19



Source: AEMC analysis

Under current access arrangements in the NEM, generators have a right to be connected to the network but they have no right to be dispatched. Generators can be constrained off at any time due to congestion on the network. Congestion therefore impacts the quantity of generation that an individual generator can dispatch, and hence the revenue it receives from the spot market.

There are limited tools available in current access arrangements to help participants manage the financial risk of congestion, creating a significant risk of decreased revenue for market participants. Attempts to quantify this risk have also proved difficult for market participants. These factors ultimately impact consumers because they discourage otherwise efficient investment in the sector.

In addition, the price does not reflect value under the current transmission access regime. All generators and storage within one of the five NEM regions face the same price for every unit of electricity provided to and consumed from the system (noting that price is adjusted to account for the effect of losses as electricity is transported across the network). That is, all generators (and storage) access the regional price for their physical generation (and consumption in the case of storage), regardless of their location within a region.

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<sup>68</sup> Sources include: AEMO, Draft 2020 ISP, December 2019, p50; TransGrid, New South Wales Transmission Annual Planning Report, 2019, p7.

This is despite the differences in the value of electricity between locations as a result of congestion. While the current arrangements provide some locational signals, these are incomplete and do not adequately incentivise new generators and storage systems to make the best use of existing and new transmission capacity. The impact of this problem was relatively small in the NEM until recent years because the level of new investment committed was relatively small.

The current arrangements do not provide strong incentives for investment to locate and operate in a way that minimises total system costs (i.e. generation and storage and transmission). These inefficiently incurred costs flow through to consumers in the form of higher bills. Similarly, the current arrangements provide no ability for generators to hedge against or manage the risk of local congestion. As a result, generators can be constrained off the system with no ability to manage this risk. Enabling generators to access risk management tools to manage congestion should also help promote both efficient locational decisions and efficient operational decisions by generators.

## 10.2. What are the options considered?

### Options already underway

Because the issues discussed in Section 10.1 have been evident for several years, some changes have already been made.

- Actioning the ISP – the ISP is a major planning reform, first published in 2018. Over the course of 2019-20, the ESB developed a set of changes to the Rules to convert the ISP into action. The 2020 ISP has recently been published and the rule changes are in effect. The ISP rules are designed to streamline regulatory processes and support the implementation of key projects identified in the ISP, while retaining a cost benefit assessment.
- Transmission access reforms – the AEMC is developing a model for transmission access reform which would supplement the work of the ISP and improve locational signals to generators. This means existing and yet-to-be built transmission infrastructure can be used more efficiently. The new access arrangements will also assist in the management of congestion on the grid and provide generators with a means to better manage the related risks to their revenues. Section 10.2.2 below outlines the work to develop new transmission access arrangements.
- Interim arrangements for REZs – given that the transmission access reform above will take some time to be implemented, the ESB is considering interim arrangements for priority REZs recognised in the ISP. While the transmission access reform is intended to provide the longer term framework, the ESB considers there may be a need for short term arrangements to support the immediate development of several REZs to meet pressing requirements. The ESB has proposed short term arrangements to meet these requirements:
  - Stage 1 seeks to build on the planning arrangements in the ISP. It is proposed that the jurisdictional planning body in a region should be responsible for undertaking detailed planning for the priority REZs identified in the ISP. The detailed assessment of a REZ, and its breakdown into a sequence of connection hubs, will refine the more general work in the ISP and provide the basis for implementation. The ESB has recently published a consultation paper on the rule changes needed to give effect to improved planning for REZs.<sup>69</sup>

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<sup>69</sup> <http://www.coagenergycouncil.gov.au/publications/energy-security-board-renewable-energy-zones-planning-consultation>

- For Stage 2, the ESB is considering developing a framework for the implementation of hubs within the REZ and providing interim access reform arrangements to support market investment in these hubs. Work on Stage 2 is underway.

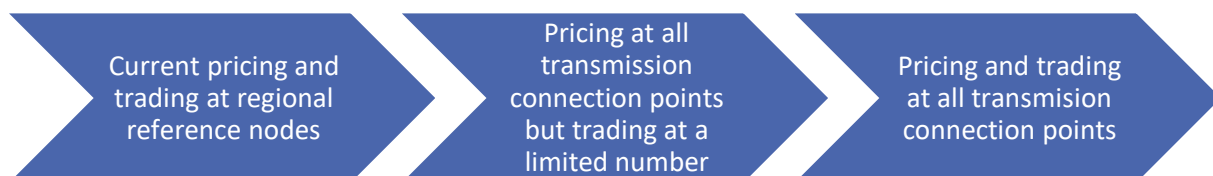
## Possible future options

### Transmission access reform

The AEMC has been working with stakeholders and consultants to develop improved transmission access and congestion management arrangements that meet future needs. The proposed transmission access regime has two core elements, common to many overseas designs:

- Locational marginal pricing (LMP) – scheduled market participants would receive/pay a price that would vary with their location. Retailers, and therefore the large majority of consumers, would continue to pay a regional price, which would preserve contract market liquidity. Nevertheless, when conditions vary between locations in the NEM, for example due to constraints on the flow of electricity, LMP will vary across the network. This will more accurately reflect the value of supplying electricity at each location in the network and make the physical elements of the system more transparent. LMP should provide improved signals for new generators over where the network has capacity to support their generation output.
- Financial transmission rights (FTRs) – these would allow participants to manage the risks of congestion by allowing them to purchase an FTR which would pay out on the differences in wholesale market prices arising due to congestion (which accumulates as congestion settlement residue). FTRs would give market participants the tools to better manage existing (and increasing) transmission congestion risks, which, in turn, would provide more revenue certainty and the confidence to invest. FTRs would be sold via a competitive auction process.

Beyond adopting these two core features of LMP and FTRs, there are a range of options for how many network points between which financial rights are traded. Options might range across a spectrum, building on the current arrangements:



There are also a number of key design choices in the design of the FTRs themselves, the time period they cover, and how they are traded. Another important issue is the implementation path.

The AEMC has been developing and refining the model, thinking through the different options over the first half of this year. It has released an accompanying technical paper, which sets out current preferences for these choices in more detail, and stakeholder feedback is being sought on this. This will be refined, and stakeholder feedback taken into account, to further develop and refine the model for the December ESB Post-2025 paper. The AEMC is also intending to provide draft rules on transmission access reform by the end of the year.

The draft model, in summary, sets out preferences for a number of key questions, including:

- How should the regional price be calculated?
- How are losses reflected in the wholesale electricity price?
- How long in advance should FTRs be available?

- Who should be allowed to participate in the FTR auction?

In particular, further work is needed over the coming months to consider questions such as whether the ability for participants to manipulate high prices under certain market/network conditions (i.e. 'load pockets') is an issue under the new access framework or not. If it is an issue, the AEMC intends to explore ways to mitigate against this.

In developing the draft model<sup>70</sup>, a number of inputs have been considered:

- Stakeholder feedback gathered through extensive consultation.
- Independent modelling by NERA Economic Consulting.<sup>71</sup>
- Estimates of the various cost implications of making various design decisions.
- International experience and learnings, drawing on the experience of the reform in numerous jurisdictions all around the world.
- Work underway in the ESB's Post-2025 market design.

The NERA modelling is set out for consultation on the ESB Post-2025 Program website. The ESB is interested in stakeholder views on the modelling and assumptions used. Key points are highlighted below for discussion.

- NERA has undertaken detailed modelling of the NEM to estimate the benefits from introducing LMPs through improved dispatch efficiency and more efficient generation, storage and transmission investment. On the basis of various assumptions, large benefits are estimated over the next 20 years.
- NERA has also reviewed international experience, which it found to be broadly consistent with its NEM modelling. NERA's findings from reviewing studies overseas regarding operational benefits from the introduction of locational marginal pricing and financial transmission rights are also set out in the accompanying paper.
- The regional price is typically higher than local marginal prices in the presence of congestion, meaning that under the current regional pricing regime, in the presence of congestion generators typically receive additional money compared to if they were paid the local marginal price. Under the access reforms, generators would have to pay for FTRs to access this money, with the proceeds from the sale of the FTRs being used to enhance the firmness of the FTRs and then offset consumer's bills. NERA has estimated the total reduction of bills for consumers, and this is set out in the accompanying report.

A key consideration of implementing the regimes is that generators, TNSPs and other market participants should be given time to develop their internal capabilities to operate new or changed processes under the access reform, without incurring undue operational or financial risks during the learning period. Therefore, it is proposed that generators would receive some transitional FTRs for free at the start of the regime.

The regime would be phased in over time. One example is that at the start of the regime, FTRs may only be able to be purchased from a set of pre-defined set of nodes in the transmission network. Further refinements to the transmission access model may be needed over time, as participants become more familiar with the regime; for example, the transitional FTRs would expire and extra nodal prices could be added between which FTRs could be bought in an auction.

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<sup>70</sup> All related material including latest reports on modelling can be found at: <https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and>

<sup>71</sup> <https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and>

## Investor funding in the shared transmission network

A potential future evolution of the access arrangements that could complement a congestion management regime is one that provides a way to encourage investors to fund incremental development in the shared transmission network. The network could be augmented or elements brought forward, reducing congestion, and the investor could receive a right over the additional transfer capacity. Ideally that right could be similar to an FTR, providing a financial return on investment and assisting market participants to manage congestion costs.

This could be useful to parties wishing to fund REZs or generators seeking to connect in areas where the shared network does not provide the transfer capacity needed to minimise congestion and needed to manage the financial risk of congestion. This could be complementary to a future transmission access regime and provide an additional option to purchasing access on the existing grid or to managing congestion in areas of the grid where FTRs are not trading (depending upon the design option chosen).

For example, if a market participant agreed to fund investment in transmission assets that provided an additional 100MW of transmission capacity between two points in the transmission network, it would receive 100MW of FTRs between those two points.<sup>72</sup> This would compensate the participant if that transmission capacity was used by other participants, and thereby overcome the existing “free-rider” problem associated with private investment in the shared transmission network.

### 10.3. Questions for stakeholders

1. The second ISP has now been released. Do you have any comments on how its implementation can be made more efficient and timely?
2. The cost of major transmission investment projects is of concern. Do you have any suggestions on how these projects can be built for less than currently expected? Why have costs increased so markedly? Given the rising costs, are there alternative approaches to transmission project development, design and implementation which could lower the cost?
3. The development of REZs is important for the transition underway in the NEM. Do you have any suggestions on how large-scale priority REZs can be more efficiently developed and connect into the network?
4. NERA Economic Consulting’s modelling of the benefits of introducing transmission access reform in the NEM has been published. What do you think about the modelling and assumptions used? What does this suggest about how fit-for-purpose the current access regime is? If you are unsure of the merits of locational marginal pricing and FTRs, what other suggestions would you make about how risks of congestion might be managed by generators?
5. The AEMC has released an updated technical specification paper on the transmission access reform model, alongside this report. The updated proposal provides additional information on the options regarding the design of the instruments, pricing, and trading. How well do you think the proposal would address the identified challenges?
6. What are stakeholder views on the current suite of locational investment signals? The ESB welcomes stakeholder views on alternative solutions to address the need for improved locational signalling for generators.

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<sup>72</sup> Alternatively, the 100MW of FTRs might be auctioned and the proceeds from the sale distributed to the funding participant.

## 11. OVERALL MARKET DESIGN – INTERDEPENDENCIES AND EVALUATION

### 11.1. Interdependencies between initiatives

In the previous sections 4 to 10, a range of market design reform options are set out. These followed a brief discussion in earlier sections about why the current market design is no longer completely fit for purpose. Each of the market design initiatives addressed one of seven particular issues: resource adequacy, thermal generation retirement, essential system services, scheduling and ahead markets, a two-sided market, demand flexibility and DER, and transmission access and the coordination of transmission and generation. Each of these initiatives is interdependent with the others to varying extents.

A key element of this Post-2025 market design work is to assess how these many reform options fit together. It is important that the market design is:

- Congruent – the elements fit together to deliver a coherent design.
- Efficient – the elements take a ‘system-wide’ approach to account for interdependencies and overlaps with other reforms.
- Holistic – together the elements enable opportunities to be unlocked in other areas these trade-offs are considered.
- Least cost – together the reform elements meet the needs of the transition at least cost to consumers.

The post-2025 reform options also need to work with other reforms underway in the broader policy environment (for example, rule changes lodged and already initiated by the AEMC). Where interdependencies exist, these relationships may have implications for changes to current systems, tools and processes. The market design elements should be coherent and facilitate the broader reform agenda, while being proportionate and not imposing unnecessary costs onto consumers and market participants (for example due to inefficient sequencing of activities).

One of the biggest value-adds of the Post-2025 reform program is the opportunity to map out a coherent long term reform path.

Ordinarily, incremental changes are considered on an individual basis, and this may not be the best way to consider a whole of market redesign. The value of considering a broader program of reform is that it enables a systems thinking approach to be taken, so implementation of design elements can be optimised together where possible. This also means it is important the evaluation process carefully considers how the different program elements work together, to limit the risk of unintended consequences as far as possible.

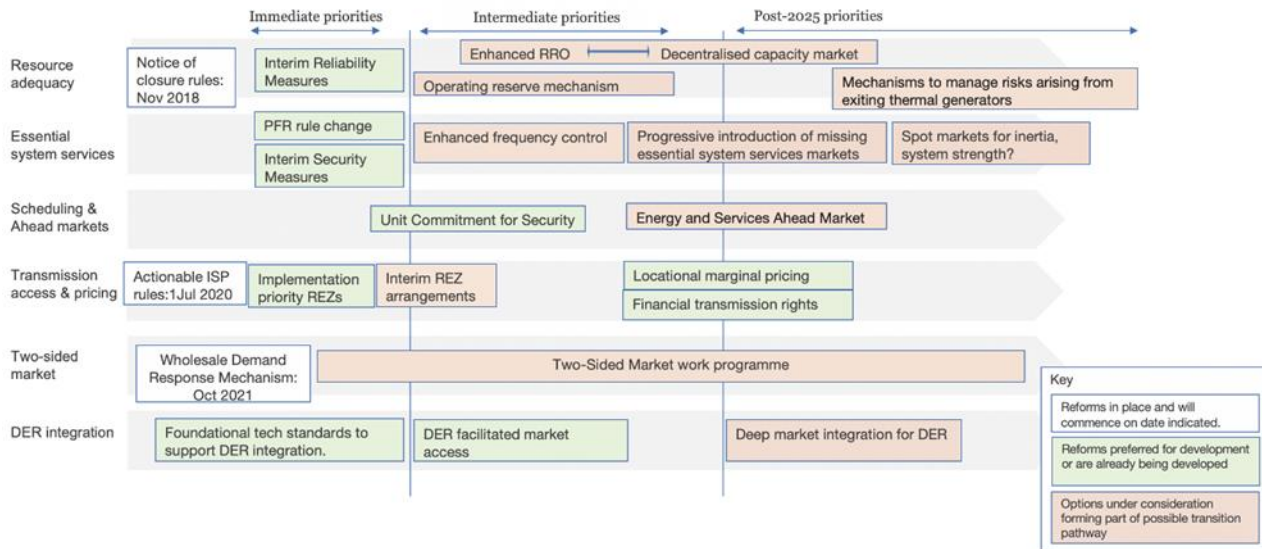
Progressive implementation of the Post-2025 reforms provides a managed evolution of the market and allows participants the opportunity to adapt to reform. The high-level plan up to and beyond 2025 sets out, for each MDI, where a mix of more sophisticated tools, systems and arrangements may be needed to address the strategic challenges as these evolve over the next 10-15 years. While some early and interim measures will be delivered to address needs already emerging within the system, a progressive approach for delivering initiatives enables the market to respond to each set of measures before building further on these with additional reforms. This approach also enables a continued focus on delivering changes needed to support the transition at least cost to consumers.

A representative example is illustrated in Figure 36 below. This figure represents an indicative pathway for the measures highlighted within this report, and how a progressive and coordinated implementation may, at a high level, proceed. While the measures represented here are not necessarily recommended options, depicting them over these horizons shows the potential to build on the changes made in each phase. By introducing a suite of measures progressively,



there is scope to gain better insights about how each set of measures may, in combination, work to address the evolving challenges and unlock other opportunities. The risk of layering multiple solutions onto problems is reduced.

FIGURE 36 PHASED MARKET DEVELOPMENT



These considerations are key as we move into the next phase of design and evaluation. For example, if we reflect on the measures highlighted in the 'Up to 2025' horizon in Figure 36, it is clear that these initiatives address issues that have already emerged across multiple program workstreams:

- Introducing an *operating reserve* could provide a mechanism to secure additional resources with capabilities needed to support system reliability and security, working to alleviate concerns regarding the availability of dispatchable capacity as the system transitions. It also opens up the potential for a broader range of service providers to participate in providing these services (including *demand based service providers*). Also, an enhanced RRO or decentralised capacity market could provide further assurances to policy makers that necessary investment in the market will occur as thermal generators retire.
- In parallel with the work to consider frameworks that support the *transmission system of the future*, work to facilitate the *participation of DER* is focused on developing frameworks that support the interface between distribution and wholesale systems. As technology continues to evolve, and with it our understanding of its performance and capabilities, regulatory frameworks and standards need to adapt to meet these changing needs.

The congruency of reforms over the short and medium term through to longer term horizons needs to be evaluated. Reforms that are likely to be required and delivered over those periods can be considered together, enabling an assessment of how the combined changes impact consumers, the market and system. This approach also enables changes in future phases to build on other changes that have taken place already.

## 11.2. Evaluation approach

The ESB must satisfy itself that any changes to the existing design or recommendation to adopt a new market design meet the NEO.

The ESB intends to evaluate individual solutions, as well as assess how potential market design option(s) deliver outcomes as a whole package of reforms. A proposed evaluation framework has

been developed, informed by feedback from submissions to the September Issues paper. The framework includes an Interdependencies and Evaluation Workgroup as well as workgroups examining separate workstreams.

This framework is intended to:

- A. Outline the relevant principles the ESB will use in considering whether the NEO is satisfied.
- B. Provide transparency regarding the evaluation process, to support feedback loops and enable comparison of options emerging within and across workstreams. In practice, it is likely that the evaluation will be an iterative process as market design option(s) are developed, with feedback sought from workgroups on proposed packages to meet transitional requirements as well as options for more enduring longer-term arrangements.

An overview of the proposed evaluation framework is set out in Appendix 1.

## 12. ENGAGEMENT WITH STAKEHOLDERS

The Post-2025 program is an inherently complex undertaking requiring a robust evidence base, a disciplined future-focus, and the structured engagement of numerous stakeholders. For the remainder of the project, stakeholders will be engaged in three distinct project phases:

1. Problem refinement and options analysis (March to October 2020) – inclusive of this consultation paper and consultation period.
2. Options shortlisting and convergence (October to December 2020) – to refine and further develop options that might be considered as part of the final recommendations to Energy Ministers.
3. Development and evaluation of recommendations (January to mid-2021) – to evaluate detailed market design options ahead of making final recommendations to Ministers.

Significant sector-wide engagement has already occurred through an extensive program of events during the problem refinement and options analysis phase.

This proactive approach has enabled diverse stakeholders to keep track with, and progressively contribute to, the options analyses in real time, and well ahead of the key points of formal consultation in August and December 2020. Significant efforts have been made to offer a program of two-way stakeholder engagement consistent with the 'Involve' classification on the IAP2 spectrum<sup>73</sup>.

A summary of key themes raised by stakeholders to date, and the ESB's response, is included in provided on ESB Post-2025 program website.

Given the COVID-19 situation, all the above workgroups have operated on a virtual basis. The ESB recognises that this has been a challenging period for many stakeholders and has sought to provide a balance of information sharing on the content development and facilitated 'open mic' stakeholder discussion sessions. This combination has been well received by stakeholders as providing the opportunity to engage deeply with the technical detail and progressively raise issues, concerns or suggestions in real time to enhance the options analysis process.

The ESB will continue close engagement with stakeholders over the next two phases of the project. The structure and format of program workstreams to date has supported the consideration of issues across the initiatives. As we move into the evaluation phase, we will work with stakeholders to adjust the structure of these workstreams and stakeholder forums to better meet what is needed to support this.

Details of open stakeholder events and their outcomes will be published on the Post-2025 market design website.

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<sup>73</sup> <https://www.iap2.org.au/resources/spectrum/>

### 12.1. Consultation process and submissions

The ESB invites comments from interested parties on this consultation paper by 19 October 2020. Please respond to the ‘questions for stakeholders’ in this paper in your submission.

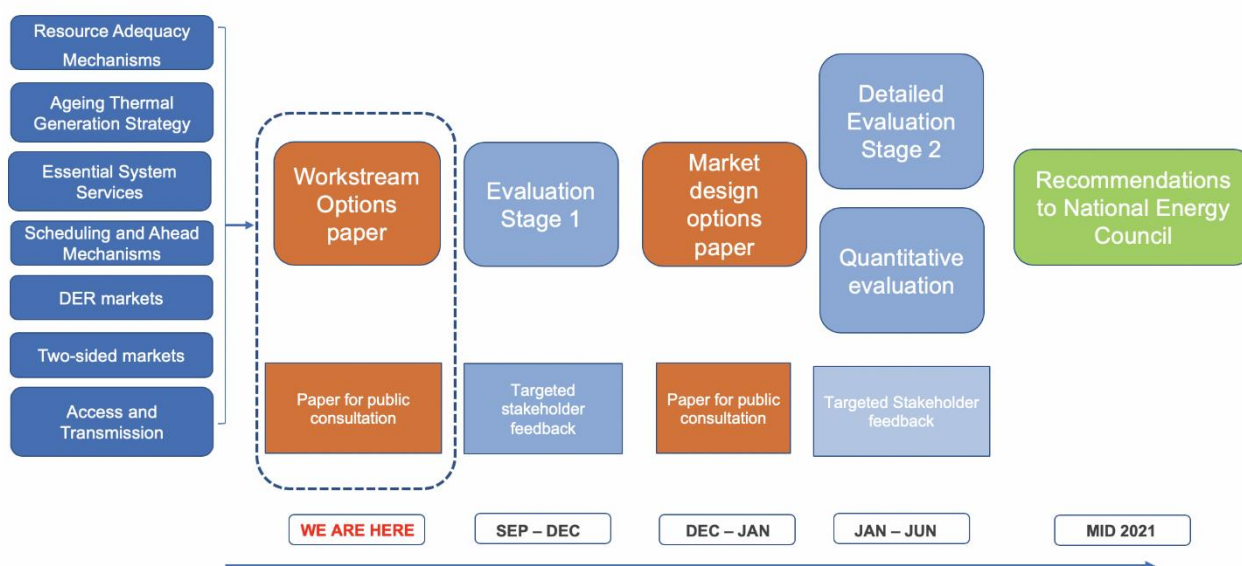
<b>Submission close date</b>	19 October 2020
<b>Lodgement details</b>	Email to: <a href="mailto:info@esb.org.au">info@esb.org.au</a>
<b>Format of submission document</b>	Must be in Word
<b>Naming of submission document</b>	[Company Name] Response to P2025 Market Design Consultation Paper
<b>Late Submissions</b>	Late submissions will not be accepted
<b>Publications</b>	Submissions will be published on the COAG Energy Council’s website, following a review for claims of confidentiality

## Appendix – Evaluation framework

A focus of the Post-2025 program has been to develop a clear framework to support consistent and transparent evaluation of the multiple workstream initiatives. It is clear that the interdependent nature of many of the design elements and issues being addressed means consideration of any market design option(s) requires a systems-wide approach, and evaluation needs to consider the impacts from multiple perspectives.

An overview of the proposed evaluation framework is set out in Figure 37 below.

FIGURE 37 OVERVIEW OF POST-2025 PROGRAM EVALUATION FRAMEWORK  
**PROGRAM OVERVIEW AND NEXT STEPS**



This framework has been informed by feedback across a number of stakeholder workstreams, including the Interdependencies and Evaluation Workgroup. As discussed in these workstreams, and outlined further in the discussion below, this framework is intended to provide transparency regarding the evaluation process to support feedback loops and enable comparison of options emerging within and across workstreams. In practice, it is likely that the evaluation will be an iterative process as market design option(s) are developed, with feedback sought from workgroups on proposed packages to meet transitional requirements as well as options for more enduring longer term arrangements.

Introduction of a two-stage evaluation process is intended to support assessment of potential solutions at the workstream level, enabling the pros and cons to be considered across all emerging solutions. However, it is also intended that this 'first pass' assessment will enable a short list of proposals to proceed for consideration as part of any market design options. The second stage of evaluation will therefore consider how well proposals work together, their congruency, and how well any market design option(s) achieves the principles set for the broader reform program.

This two-stage process, including the proposed criteria and principles for each stage, is discussed below.

## Stage One – workstream level assessment

The Post-2025 workstreams (MDIs) are each set out for discussion in section 4-10. For the first stage of the evaluation, potential solutions developed within each workstream will be assessed against the criteria set out in Table 6 below.

TABLE 6 STAGE ONE – WORKSTREAM LEVEL ASSESSMENT CRITERIA

Assessment criteria	Description
1. Facilitate effective outcomes for all consumers - via competition where efficient and complemented by effective consumer protections and regulation where appropriate.	Rivalry in competitive markets should promote efficiencies and innovation, but should be complemented by effective consumer protection regulations to mitigate against poor or misleading conduct, and to protect those who are vulnerable or unable to safeguard their interests. Frameworks should also ensure that regulated entities such as network monopolies are subject to effective economic regulation that promotes efficiency, reliability, system security and safety.
2. Promote signals for efficient investment and operations	Efficient arrangements maximise the provision of price signals that reflect the marginal cost of the provision of a particular product or service, as well as any positive or negative externalities, in order to encourage timely and efficient decision-making in both investment, demand and operational time-scales. Efficient outcomes will be enabled across productive, allocative, technical and dynamic dimensions, supporting more efficient and effective use of capital and energy. While price signals are preferred, there may be other signals that can also be provided such as the greater provision of market information to participants.
3. Appropriate cost and risk allocation	Risk and cost allocation, and the accountability for investment and operational decisions should rest with those parties best placed to manage them.
4. Technology neutrality	Regulatory arrangements must be flexible to changing market conditions and take into account the full range of potential market and network solutions. They should support the right mix of resources over time, reflecting supply and demand side participants and solutions, technological developments and changes in behaviour, rather than be designed solely for the prevailing technology or business model of the day.
5. Cross-market integration	Costs to consumers will be minimised when markets complementary to energy, such as ancillary services and emissions, are designed in a way that is consistent with the price discovery mechanism in the electricity market.
6. Regulatory and administrative costs	Practical, operational and compliance impacts result in minimal unintended consequences. Changes to regulatory frameworks come with associated costs. These costs include both those imposed to implement change and the ongoing costs associated with making the change.
7. Ability to deliver a reliable system and support system security	Security and reliability challenges need to be considered as supply and demand become more variable and uncertain, and the industry transitions away from generation that traditionally delivered security services.

It is intended that the workstream level evaluation would include the following in an assessment against the above criteria, noting that each of the above criteria allow for a consideration of spectrum of options and trade-offs, to assist stakeholder consideration on the assessments undertaken:

- Pros/cons of potential solutions against each criterion – enabling comparison of relative benefits.
- Identify where solutions may address issues over the transition period, or whether the benefits/risks are more likely to be accrued over the longer term.
- Provide discussion of factors considered with each criterion.

Continued evaluation of potential workstream solutions will be carried out and considered by the evaluation work groups between now and the end of this year. Directions set out in this paper by the ESB Board, together with stakeholder feedback, will inform the priority options for further development within these workstreams. Where the range of potential options can be streamlined



to the most viable solutions, this will enable greater focus on those options with the greatest potential value to address the strategic challenges.

This evaluation will consider the congruency of potential solutions with other design initiatives, as well as with other reforms and rule changes progressing through the AEMC and broader policy landscape.

Market design options will be developed for consideration with combinations of the workstream solutions that achieve the best overall outcomes against the assessment criteria. As the reform program is intended to deliver a phased implementation, market designs are likely to include a combination of changes to reflect needs for the transition and over the longer term.

### Use of customer archetypes to inform evaluation

The ESB intends that the use of customer archetypes will assist consideration of how different aspects of the reform program might work in practice with different customer groups.

As noted earlier, due to the high degree of customer interaction with the two sided markets workstream, the ESB proposes to use customer archetypes to inform this evaluation (see Section 8).

As part of the evaluation for each design option, consideration will be given to how well each market design option addresses the issues and priorities identified by consumers in respect of the current arrangements, to outline a clear view of what each design option will deliver for consumers over the transition and long term phases (in respect of both avoided risks and potential opportunities unlocked). The use of archetypes will also help to inform where it may be beneficial to explore supporting or complementary measures to improve outcomes to a greater proportion of consumers.

### Stage Two – reform-wide assessment

The second stage of evaluation will be carried out in respect of the market design option(s), reflecting the best combinations of viable solutions brought together from across the MDI workstreams to meet the NEO. That is, each of the elements contributing to the market design options would meet the criteria set out in Stage One, with some options likely delivering a better achievement of some criteria than others.

For the second stage of evaluation, market design options will also be assessed against the principles set out in Table 7 below.

It is intended that evaluation of the market design option(s) against these principles would enable a transparent consideration of the, often competing, objectives of reform.

This stage of the evaluation also recognises, and is intended to support, holistic consideration of the options for reform. This will enable, for example, consideration for certain design elements to be phased in earlier or later than others to improve outcomes at a system-wide level.

TABLE 7 STAGE TWO – REFORM-WIDE ASSESSMENT PRINCIPLES

Principles	Description
<b>A. Proportionate</b>	The scale of change delivered by the design is relative to the scale of the risk and problem being mitigated and/or the potential opportunity to be gained. Design solutions may need to evolve over time in response to growing risks / opportunities; but should target the proportionate degree of change in response to the needs of the transition.
<b>B. Credible</b>	Capacity to evolve from current policy settings and achieve broad support. Design provides a clear and objective basis for where amendments may be warranted to phase in certain elements of the framework.

Principles	Description
<b>C. Affordable and equitable</b>	Costs associated with market design are affordable and fair. Design works to optimise use of resources for the benefit of all consumers, providing enhanced opportunities for consumers to engage in and receive value from new service models.
<b>D. Community support</b>	Public and consumers can understand the rationale and general direction of market design. Alignment with social license expectations of community (i.e. energy as an essential service, applies appropriate degree of customer protections, supports and enables future pathways for jobs, growth, and environmental concerns).
<b>E. Viable and coherent</b>	Elements of the design are congruent, with interdependencies considered and highlighted. The design presents a viable and effective option that clearly addresses the problems identified. Design provides clarity and confidence regarding scope and timing of changes and a pathway for future transition needs.
<b>F. Resilient and flexible</b>	Ability for the design to withstand and be flexible to changes in policy targets, political developments and technological change in the broader policy landscape. The design should be resilient and flexible to such changes but enable new technology developments and business models to emerge and meet the needs of energy consumers.
<b>G. Supports lower emissions</b>	Ability for the design to align with decarbonization objectives and deliver reduction in carbon emissions.

### Evaluation of market design option(s)

Option(s) for market design will be issued for consultation around late December 2020/early January 2021. As discussed, options will build on the solutions emerging from the workstream processes and design will be informed by stakeholder input and feedback.

A quantitative evaluation of any market design option(s) will be undertaken over Q1-Q2 2021, with recommendations on future design being made to the former COAG Energy Council by mid-2021. A detailed design process will begin concurrently in 2021 to support a phased implementation of priority initiatives.

## Appendix – Summary of Questions for stakeholders

<b>Section 1</b>	<b>Consultation and Submissions</b>
1	The potential solutions and how well the characteristics of these solutions address the challenges identified with the current market design. Where alternative solutions can be identified for discussion, these would also be welcome.
2	The proposed timing of the implementation of the changes to the market design and reasons for any alternative timing you may wish to propose.
3	Our proposed approach to classifying the broad range of consumer needs, and what may be alternative or complementary incentives or regulatory measures (including consumer protections) to consider in support of these needs.
4	The proposed approach and criteria to evaluate the range of potential solutions identified within each workstream, as well as for assessing market design option(s) to be developed later this year.
<b>Section 4</b>	<b>Resource Adequacy Mechanisms – Market Design Initiative A</b>
1	Do you have views on whether the current resource adequacy mechanisms within the NEM are sufficient to drive investment in the quantity and mix of resources required through the transition?
2	Do you have views on whether the short-term signals provided by an operating reserve mechanism or market would provide adequate incentives to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What impact could an operating reserve have on financial markets? What are the benefits of this approach? What are the costs and risks?
3	Do you have views on whether the signals provided by an expanded RRO based on financial contracts or a decentralised capacity market would provide the type of incentives participants need to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner. What are the benefits of this approach? What are the costs and risks?
4	Do you have views on how an operating reserve mechanism and/or expanded RRO would impact the need for and use of RERT and the interim reliability reserve if they were introduced into the NEM? What adjustments to the RERT and/or interim reliability reserve may need to be made so that they are complementary and not contradictory or duplicative?
5	Do you have views on how RAMs (current or future) can better be integrated into broader jurisdictional policy priorities and programs? Should jurisdictions reflect broader policy priorities through the nature of obligations placed on retailers in an enhanced RRO or decentralised capacity market, or through the qualifying requirements for participation in an operating reserve?
<b>Section 5</b>	<b>Ageing Thermal Generation Strategy – Market Design Initiative B</b>
1	Have we correctly identified the cost, reliability and security risks to consumers from the transition away from thermal generation?
2	Are these risks likely to be material, particularly those relating to consumer costs?
3	Are there additional or alternate market design approaches that will ensure the transition away from thermal generation is least cost to consumers?
4	Should the ESB consider and develop any of the options outlined in this section further?
<b>Section 6</b>	<b>Essential System Services – Market Design Initiative C</b>
1	What feedback do you have on the proposed provision of an operating reserve through spot market provision? How could this interact with operating

	reserve procurement for resource adequacy? Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment needed for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?
2	What are your views about developing Fast Frequency Response with FCAS and developing a demand curve for Frequency Response? Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements. What additional mechanisms might be needed to foster investment for a post-2025 NEM. What are the benefits of this approach? What are the costs and risks?
3	What are your views on the proposed structured procurement for inertia and system strength by way of NSP provision, bilateral contracts and generator access standards, or through a PSSAS mechanism? Which approach is preferable, what are the relative benefits, risks and costs? Should the ESB instead prioritise the development of spot market for or structured procurement of inertia? What are the relative benefits, risks and costs of such an approach?
4	Given future uncertainties and the potential pace of change, what level of regulatory flexibility should AEMO and TNSPs operate under? What are the benefits, risks, and costs of providing greater flexibility? What level of oversight is necessary for relevant spending? Are there specific areas where more flexibility should be provided or specific pre-agreed triggers?
<b>Section 7</b>	<b>Scheduling and Ahead Mechanisms – Market Design Initiative D</b>
1	The ESB is interested in stakeholder feedback on the options for the ahead mechanisms we have outlined. Are there additional options? Are the options for a UCS and UCS + ahead markets fit for purpose?
2	The ESB proposes to develop the UCS tool for implementation. Do you support the UCS concept? What factors and design features should be considered for detailed development?
3	The difference between actual and forecast residual demand leading up to real time dispatch has been far more stable in the last decade than the difference between actual and forecast prices (\$MWh) leading up to real time dispatch. What do you consider the drivers of this may be?
<b>Section 8</b>	<b>Two-Sided Markets – Market Design Initiative E</b>
1	What do you consider are the risks and opportunities of moving to a market with a significantly more active demand side over time? How can these risks be best managed?
2	What are the barriers preventing more active demand response and participation in a two-sided market? What are the barriers to participating in the wholesale central dispatch processes?
3	Do you think any other near-term arrangements or changes to the market design can be explored in this workstream?
4	What measures should be deployed to drive consumer participation and engagement in two-sided market offerings, and what consumer protection frameworks should complement the design?
5	What might principles or assessment criteria contain to help assess whether it is timely and appropriate to progress through to more sophisticated levels of the arrangements?
6	The ESB is considering combining the DER integration (below) and two-sided markets workstreams, or elements thereof, do stakeholders have suggestions on how this should be done?

<b>Section 9</b>	<b>Valuing Demand flexibility and Integrating DER – Market Design Initiative F</b>
1	Are there any key considerations for the incorporation of DER into the market design that have not been covered here? For DER to participate in markets, it needs to be responsive. How should the post-2025 project be thinking about enabling responsive DER?
2	In the next phase of the project the ESB proposes to focus on development of a detailed DER market integration proposal. What are the most important priorities for DER market integration? The ESB is considering combining the DER integration and two-sided markets workstreams, or elements thereof, do stakeholders have suggestions on how this should be done?
3	How can we ensure that owners of DER can optimise the benefits of their DER assets over time as technology and markets evolve? How do we time reforms to manage the costs and benefits for DER owners?
<b>Section 10</b>	<b>Transmission Access and the Coordination of Generation and Transmission – Market Design Initiative G</b>
1	The Integrated System Plan is now in its second year. Do you have any comments on how its implementation can be made more efficient and timely?
2	The cost of major transmission investment projects is of concern. Do you have any suggestions on how these projects can be built for less than currently expected? Why have costs increased so markedly? Given the rising costs, are there alternative approaches to transmission project development, design and implementation which could lower the cost?
3	The development of Renewable Energy Zones is important for the transition underway in the NEM. Do you have any suggestions on how large-scale priority REZs can be more efficiently developed and connect into the network?
4	NERA Economic Consulting's modelling of the benefits of introducing transmission access reform in the NEM has been published. What do you think about the modelling and assumptions used? What does this suggest about how fit for purpose the current access regime is? If you are unsure of the merits of locational marginal pricing and FTRs what other suggestions would you make about how risks of congestion might be managed by generators?
5	The AEMC has released an updated technical specification paper on the transmission access reform model, alongside this report. The updated proposal provides additional information on the options regarding the design of the instruments, pricing, and trading. How well do you think the proposal would address the identified challenges?
6	What are stakeholder views on the current suite of locational investment signals? The ESB welcomes stakeholder views on alternative solutions to address the need for improved locational signalling for generators.

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