National Electricity Market wholesale market settings review

Final Report

December 2025

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Acknowledgement of Country

We acknowledge the Traditional Owners of Country throughout Australia and recognise their continuing connection to land, waters and culture. We pay our respects to their Elders past and present.

Acknowledgements

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Preface

Electricity is one of the true foundational pillars of Australia's economy and society. Many sectors are described as essential, but few are as consequential as the power system. At the same time, electricity generation accounts for roughly one-third of Australia's greenhouse gas emissions. Meeting our legislated climate targets will therefore require every part of the sector, including governments, market bodies, industry participants and consumers, to work together to deliver a net zero system that remains affordable, reliable and fair.

At the core of this system sits the National Electricity Market (NEM), an intricate and interconnected marketplace that supplies electricity to millions of Australians every second of every day. The challenges confronting the NEM are significant, but they are not beyond our capacity to address. This Review has taken a clear-eyed and methodical look at the state of the market and the reforms required to place it on a stable, modern and efficient footing. In many respects, our recommendations call for a return to the core drivers of microeconomic reform that informed the creation of the NEM in the 1990s: allocative, productive and dynamic efficiency. These drivers remain as relevant today as they were then.

The transformation underway is profound. Millions of households and businesses are now active participants in the power system through small-scale solar, batteries and emerging demand-side technologies. These developments create substantial opportunities to improve system efficiency and utilisation, reduce costs over time and deliver better outcomes for consumers. Harnessing these opportunities requires a coherent policy and regulatory framework that is forward-looking but grounded in evidence.

The Panel has approached this work with care, humility and a strong sense of responsibility. We have built upon the substantial analytical and policy foundations laid by industry, academia and previous reform efforts, including the Finkel Review, the work of the Energy Security Board, and the contributions of governments across the NEM. Our aim has been to complement, not duplicate, the important work underway within the Australian Energy Market Commission, Australian Energy Regulator, Australian Energy Market Operator and the Australian Competition and Consumer Commission.

On behalf of the Panel, I want to acknowledge the considerable effort that has contributed to this Review. I extend my sincere thanks to my fellow Panel members Ms Paula Conboy, Ms Ava Hancock and Mr Phil Hirschhorn for their expertise and judgement, and to the Secretariat for their outstanding analytical and organisational support. I am also grateful to the many stakeholders who have engaged with us openly and constructively throughout this process. This includes representatives from governments, market institutions, generators, retailers, networks, investors and consumer groups across the NEM, as well as the hundreds of individuals and organisations who provided formal submissions in response to our consultation processes, including in response to the Draft Report.

Stakeholders have noted the unique way in which the Review went about its task of engaging with stakeholders. While the recommendations represent the views of the Panel, the regular cadence of engagement has resulted in recommendations which, in the Panel's mind, were co-developed with energy stakeholders.

This Final Report sets out a practical and actionable reform pathway to support Australia's clean-energy transition while safeguarding the long-term reliability and affordability of electricity services.

Thank you

Timothy Nelson

Tim Nelson
Panel Chair

Background to the report

Scope

The scope of this review was determined by the Terms of Reference issued by the Australian Government on behalf of the Energy and Climate Change Ministerial Council (ECMC) (**Appendix A**). Per the Terms of Reference, the Panel is to recommend future market settings to promote investment in firmed, renewable generation and storage capacity in the National Electricity Market (NEM) following the conclusion of Capacity Investment Scheme tenders in 2027. The Panel is to make actionable recommendations to support the development and staged implementation of reforms to the NEM wholesale market that support the achievement of the National Electricity Objectives.

In undertaking the review, the Panel has considered interactions with the NEM reliability framework, governments' renewable energy targets and policies, and the importance of decarbonising Australia's electricity system, to help achieve the Australian Government's legislated commitment to a 43% reduction in emissions on 2005 levels by 2030 and net zero emissions by 2050. Implementation of the reforms was also considered, including the requirement for agreement at ECMC before amendments to the National Electricity Law and National Electricity Rules can be progressed.

Explicitly excluded from the scope of the review were options that involve implementation of carbon trading schemes and/or carbon markets and options that entail government support for new fossil fuel generation. For avoidance of doubt, the Panel has determined that fuel markets and planning assessment reform were also out of scope of this review. Retail pricing and network tariffs were relevant only to the extent they interact with the NEM.

Process

In the first phase of this review the Panel engaged in open and collaborative dialogue with stakeholders across the NEM, including representatives from governments, market bodies, generators, retailers, network providers, investors and electricity consumers. The Panel received more than 100 formal submissions, held more than 200 formal stakeholder meetings, and engaged in more than 40 hours of co-design workshops with jurisdictions, market bodies and other stakeholders, issued more than 30 targeted surveys and structured interviews and held lunch-and-learn sessions connecting Australia's internationally renowned academic expertise with senior officials.

Building on the engagement undertaken to inform the draft recommendations in the first phase, the second phase provided an opportunity for stakeholders to review and respond to the proposed recommendations in detail. The Panel received over 120 formal submissions (**Appendix B**) in response to its Draft Report. In addition to the formal submissions, this phase of the review also brought together key industry leaders through direct interviews, co-design working groups, and consultation on discussion papers where the Panel called on the expertise of key stakeholders to consider aspects of the draft recommendations in detail. These sessions helped the Panel to deepen its analysis, refine its key recommendations and develop the Implementation Roadmap (available at section 1 of the **Supplementary Materials**).

The Panel also piloted a novel contracts co-design process to inform **Recommendation 7**, outlined further in **Chapter 4: Maintaining liquidity in the derivatives market**. Participants noted their strong support for the process being embedded in the Panel's recommendations. The Panel also collaborated with industry and consumer representative bodies on a weekly basis through the second half of the review. This allowed for iteration of policy around the Panel's recommendations. The Panel is grateful to these peak bodies for their thoughtful contributions to this process.

Extensive communication across industry, with over 450 meetings held throughout the review, has helped the Panel ensure that the final recommendations are grounded in the collective insights of industry participants, government bodies, academics and international experts. By engaging comprehensively in the review process, the Panel has ensured that its recommendations present innovative and purpose-built solutions for Australia's NEM.

In this Final Report, the Panel has replicated much of the Draft Report's content but outlined clearly how stakeholder feedback has helped shape and amend the final recommendations. Specific feedback is woven into the main body of each chapter and also summarised in clearly identified sections throughout the report.

A package of Supplementary Materials has been published alongside this report. These materials provide a blueprint that reflects the Panel's views on how its major recommendations should be implemented. The Panel's hope is that if agreed by energy ministers, these additional documents provide a starting position for policymakers when developing and consulting on the implementation of the detailed package of reforms in 2026.

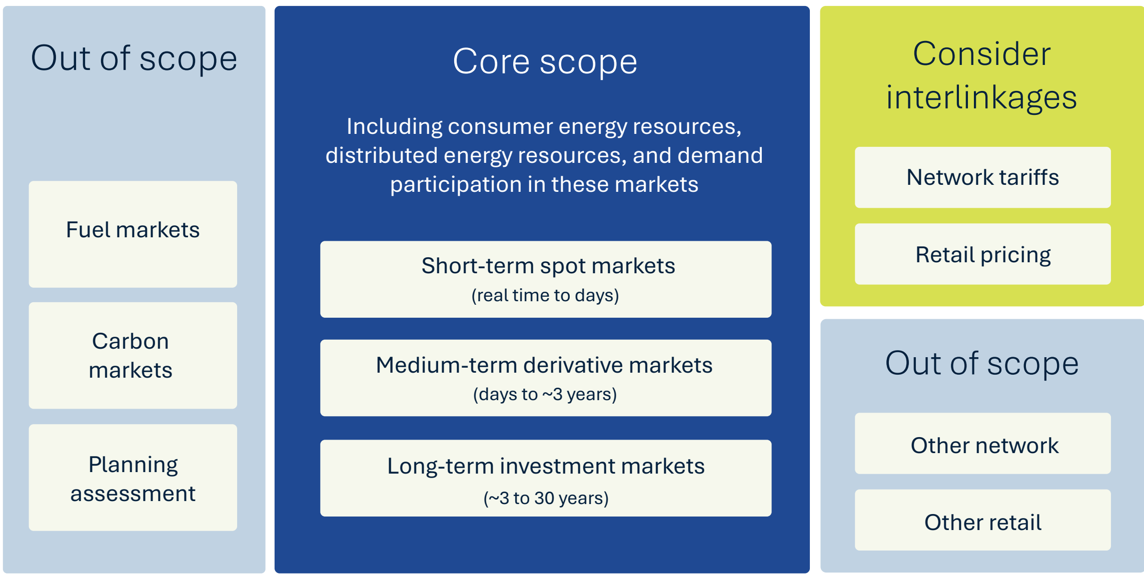
Executive summary

The Panel was tasked with reviewing the National Electricity Market (NEM) wholesale market settings to support investment in firmed renewable generation and storage capacity following the conclusion of Capacity Investment Scheme (CIS) in 2027 (see full Terms of Reference at **Appendix A**). This review builds on the legacy of earlier reviews that have grappled with similar challenges, including the Energy Security Board's Post-2025 Market Design (2021), the Independent Review into the Future Security of the National Electricity Market (2017) and the Australian Competition and Consumer Commission's Retail Electricity Pricing Enquiry (2018). Many of the core challenges identified in these reviews persist and have, in many cases, become more pressing as the penetration of variable renewable energy (VRE) in the system reaches record highs and the scheduled closure of ageing thermal generation draws nearer.

The Panel's focus is specifically on the spot market, related derivatives markets and long-term investment markets, with regard to the needs of both sellers and buyers. This complements earlier review efforts, which tended to concentrate more heavily on the seller side. Put simply, the Panel considered how to better link these markets and ensure they work together for the end consumer – with the spot market facilitating efficient dispatch, the derivatives market managing risks arising from the spot market and a new Electricity Services Entry Mechanism (ESEM) extending the forward signals from the derivatives market to support longer-term investment.

Fuel markets, carbon markets and planning assessment reform are specifically excluded from the scope of this review, while other matters such as retail pricing and network tariffs and resources were considered only as they relate to their interactions with the NEM.

Figure 1 – NEM Review scope



Throughout our engagement with stakeholders across the energy sector, we have heard a consistent message: while the NEM continues to function reasonably efficiently for dispatch, the cumulative pressures across short-, medium- and long-term horizons demand coordinated, forward-looking reform. An overview of the Panel's stakeholder engagement is provided at **Appendix B**.

The NEM is facing increasing pressures. Due to changes to the way we generate and consume electricity, the NEM is becoming a system that is more weather dependent, more energy constrained, less dispatchable and less scheduled. The Panel is of the view that these issues can be resolved, and the risks of operating in an increasingly weather-dependent system can be managed.

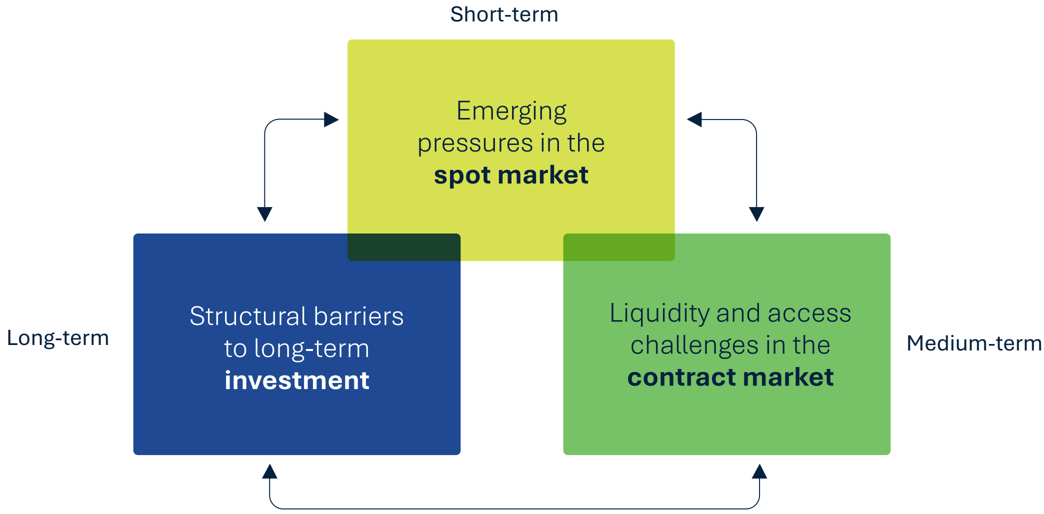
Weather dependent and energy constrained: VRE generators are central to decarbonising Australia's electricity supply. While VRE generators produce no greenhouse gas emissions, they are inherently weather dependent, introducing greater day-to-day and seasonal variability in supply. The growing reliance on weather-dependent resources increases the risk of periods where the market is energy constrained.

Less dispatchable and less scheduled: The market is also being shaped by the expanded participation of distributed energy resources. Millions of new, small-scale, price-responsive generators (i.e. batteries) are expected to enter the market. Without reform to make these resources more visible to the market operator and market participants, the market may not be able to function without significant over-investment.

Building on the NEM's original blueprint to link the short-, medium- and long-term markets

The Panel has developed recommendations that will, in our view, provide a means for seamlessly integrating medium-term risk management with efficient spot market operation, while for the first time, explicitly linking these with a long-term investment signal embedded within the National Electricity Law (NEL). It effectively builds on the NEM's original framework to link the short-, medium- and long-term markets.

Figure 2 – Emerging trends in the short-, medium- and long-term markets



Emerging operational pressures in the evolving spot market

At an operational level the spot market remains functional and broadly effective. Its core mechanisms continue to provide efficient dispatch and price discovery, even as the underlying sources of generation in the system change.

But the nature of price formation in the spot market is changing, as the system shifts from one where demand and supply-side fuel costs were the principal drivers of price to one where supply-side variability, driven by the weather-dependent nature of VRE, is increasingly important. This marks a structural change in the dynamics of the market. Prices are increasingly characterised by longer periods of very low prices when solar and wind output is strong, punctuated by sharp, often very high, price spikes during periods of low renewable generation or unexpected outages. This evolving pattern reflects a steepening and hollowing out of the traditional merit order. This pattern is expected to change further as storage becomes more ubiquitous.

Prices are likely to become predictably more variable and unpredictably more volatile. Variability, such as the predictable daily rise and fall of solar output, or seasonal wind patterns, can be forecast and managed. But volatility, such as the sudden, unplanned withdrawal of capacity during generator and network outages, or extended and unforeseen periods of low wind and solar output ('dunkelflaute'), poses more significant challenges. These shocks can be difficult to anticipate and manage, particularly as coal-fired power stations approach the end of their technical and economic lives in a 'lumpy', non-linear fashion.

While sharpening price signals introduce some challenges, they are not inherently problematic if tools exist to respond to those signals or to manage risks. Sharp price signals are a necessary feature of a market responding to changing resource characteristics and the supply-demand balance. They should be seen not as a flaw but as a sign of a market at work. The Panel notes the market will continue to respond to these signals, provided the right financial tools are available to allocate and manage risk effectively.

An energy-only, uniform clearing price market can continue to function effectively even as wind and solar, both with near-zero short-run marginal costs, become dominant sources of generation. In such a system, prices will increasingly be set not by traditional fuel costs but by the opportunity cost of storage technologies, such as batteries and pumped hydro, which shift energy from periods of low demand (or high supply) to periods of high demand. Additionally, flexible demand, such as industrial processes, electric vehicles and smart appliances, will play a critical role, with prices reflecting the value that consumers place on using electricity at different times. These dynamics ensure that even in a system dominated by variable renewables, the energy-only market can still produce efficient price signals to guide investment, dispatch and consumption.

One of the most pressing concerns in the operation of the spot market is the emergence of a growing class of non-scheduled resources that are responding to wholesale prices ('hidden participants') whose behaviour and impact on the system are not directly visible to the Australian Energy Market Operator (AEMO) and market participants in real time. This includes unscheduled consumer energy resources (CER), such as battery storage, electric vehicles and flexible demand. Traditional assumptions of inelastic demand are no longer valid. Consumers are now not only price-responsive but also producers of electricity, introducing a layer of complexity to system operation that challenges established tools and frameworks. The rise of these hidden participants risks undermining the operational integrity of the system if not properly integrated. The presence of hidden, flexible resources creates a risk of uncoordinated withdrawal or injection of power during critical periods, making it more difficult for AEMO to maintain frequency, system strength and other essential system services. The rapid growth in CER and distributed energy resources (DER) means that 'hidden' price-responsive behaviour is increasingly creating risks to efficient market outcomes and operational performance.

These issues relating to hidden participants may become critical if unaddressed. While the Panel recommends the existing wholesale spot market be retained as the core market for efficient dispatch and rewarding the provision of physical energy services (**Recommendation 1**), governments should consider measures to enhance the visibility and participation of 'hidden' price-responsive resources in the market (**Recommendation 2** and **Recommendation 3**), and pursue targeted reforms to ensure the spot market can continue to operate securely and reliably (**Recommendation 4** and **Recommendation 5**). Enhancing integration of new forms of participation, while preserving the efficient price formation at the heart of the market, is central to meeting the challenges of the next decade.

Liquidity challenges in medium-term financial markets

While the spot market governs the operation of the power system, it is the derivatives market that provides the scaffolding necessary to manage financial risk. Effective derivatives markets allow participants to transfer risk to those best equipped to manage it, enabling retailers to offer predictable prices to consumers and generators to manage the risk of uncertain spot prices. These markets perform a crucial function in maintaining confidence, enabling competition and supporting the long-term health of the NEM.

But this scaffolding is under growing strain. As noted earlier in this chapter, price signals are expected to continue to sharpen in the spot market as it becomes more weather dependent and energy constrained. These trends introduce new financial risks that need to be managed and a derivatives market is key.

Without reform, some traditional hedging instruments are likely to become less available as thermal generators exit the market. These generators have historically underpinned supply of baseload swaps and played a key role in energy-related financial markets. This structural shift is already evident in regions at the leading edge of the transition. In South Australia, declining contract liquidity and increased market concentration have raised concerns around vertical foreclosure and the erosion of competition. The ability of new or smaller retailers to access affordable hedge products is diminishing, exposing them to unacceptable financial risk and reinforcing a trend towards vertical integration. If left unaddressed, this could result in a less dynamic and more concentrated retail sector with opaque prices, reducing choice for consumers and undermining the competitive pressures that help keep prices efficient.

While direct government interventions, such as the CIS, have had the goal of providing revenue certainty for new investments, they typically do not contribute to derivatives market liquidity. Instead, they operate in parallel to the market, potentially crowding out private hedging activity and limiting the development of deeper, more transparent financial markets.

The Panel has observed encouraging signs of innovation in derivatives markets. In particular there is growing interest in new contract structures tailored to the characteristics of renewable generation. However, most of this activity is in over-the-counter markets, where deals are bilateral, bespoke and often inaccessible to smaller participants. Innovation in exchange-traded products has been slower and the tools available to manage new forms of risk have not kept pace with the underlying transformation of the generation fleet.

A well-functioning derivatives market is a precondition for a resilient and investable market-based electricity system. Rather than waiting for these issues to escalate, requiring more disruptive interventions as further coal closures occur, the Panel recommends the creation of a permanent market making obligation framework (**Recommendation 6**). This market making obligation would be underpinned by the establishment of an industry-led derivative contracts co-design process to ensure contracts available in the market reflect the needs of buyers and sellers (**Recommendation 7**). These material recommendations would be complemented by the extension of the generator availability Medium-Term Projected Assessment of System Adequacy projections to ensure sufficient market information is available to support longer term derivatives market liquidity and price discovery (**Recommendation 9**). Together, these measures should shield the NEM against future liquidity and access challenges.

Barriers to long-term investment

The long-term success of the NEM depends not only on operational resilience and financial risk management but on sustained, timely investment in the infrastructure needed to power Australia's future. This includes not only VRE but the firming, storage and essential system services that enable a secure and reliable grid. Without credible and durable investment signals, the energy transition cannot proceed in an orderly, efficient and affordable manner.

Historically, significant investment in electricity infrastructure has rarely occurred without some form of government support. The most prominent example of this government support has been the Renewable Energy Target (RET) which has historically supported the delivery of the vast majority of investment in small-scale and large-scale renewable resources. However, policies such as the RET have substituted coal-based energy with renewable-based energy, without any additional requirements to provide the other services consumers need, namely:

- **Shaping**: Moving electricity to the time of day it is needed
- **Firming**: Long-duration dispatchable capacity to deliver extra energy as needed
- **Essential system services**: Securing and stabilising the grid with a range of services, including frequency control, voltage regulation, system strength and inertia.

The CIS and state-based interventions such as the New South Wales Electricity Infrastructure Roadmap and South Australia’s Firm Energy Reliability Mechanism are the current policy instruments for de-risking private investment. But these policies sit adjacent to, rather than within, the market’s structure which is articulated through the NEL and National Electricity Rules. In the absence of a nationally consistent replacement for the CIS, investment will be driven by state-based schemes, resulting in a more complicated and fractured investment landscape, which may not match what the system needs.

The first and most persistent of the barriers to new investment is the ‘tenor gap’: a mismatch between the long-term contracts needed by sellers to finance capital-intensive assets (often 10 to 30 years) and the short-term contracting of buyers (typically three to seven years). This tenor gap is driven by a broad suite of uncertainties – technological, regulatory and demand-related. Buyers and sellers must grapple with questions around the future cost of existing and emerging technologies, the trajectory of coal closures and emissions policies and future demand. These price and volume risks mean that on one hand investors in capital-intensive new projects need long-term revenue certainty to secure financing, but on the other the buyers of that generation are unwilling to make those long-term commitments. While some uncertainty is unavoidable in any major transition, policy frameworks must strive to provide as much stability and predictability as possible.

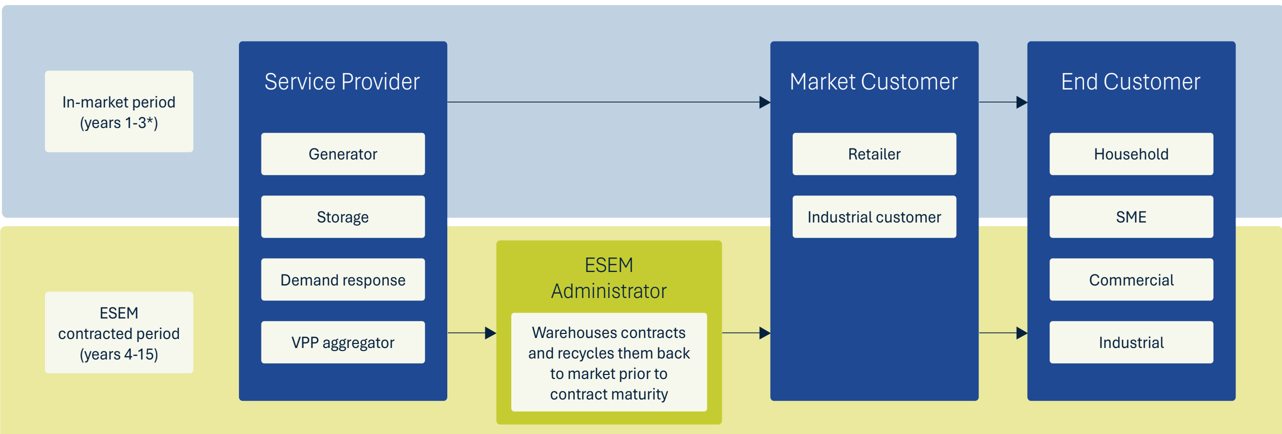
The second barrier to new investment is uncertainties driven by policies to achieve entry before exit. Consumers expect a seamless, uninterrupted transition with new generation capacity and the requisite system services in place before legacy plants retire. Unless policies to achieve timely delivery of bulk energy, shaping, firming and the requisite system services are implemented through a clear, transparent and predictable framework, they risk creating a vicious cycle: uncertainty discourages investment, delays new entry and triggers further ad hoc interventions, exacerbating the very problem they aim to solve. The question is not whether governments should continue to play a role but how they can do so in a way that supports investment, preserves competition and strengthens the long-term interests of consumers.

The Panel recommends the creation of a new ESEM (**Recommendation 10**) that addresses these barriers that investors currently face and that the market, in its current form, is not well placed to resolve. The ESEM would represent an evolution on existing schemes. The ESEM retains the core features of other recent schemes such as the CIS (i.e. reverse auctions for competitive investments, with targets determined by reliability requirements and jurisdictional emissions goals) but with tweaks to ensure it is:

- **Enduring:** A permanent feature of the NEM, embedded in the NEL
- **Efficient:** Focused support for the later years of a project's financed life, targeting only those risks the market cannot manage
- **Market-linked:** Utilising financial derivatives (defined through the contracts co-design process articulated in **Recommendation 7**) for contracting new investment and then progressively returning contracts to market to minimise costs to consumers, keep risks in-market and improve derivative market liquidity and access.

The Panel has also recommended a range of adjacent reforms to ensure regulatory settings, the innovation ecosystem and existing policies and programs align with the ESEM (**Recommendation 11**).

Figure 3 – Contract flows in the Electricity Services Entry Mechanism



*The ESEM Administrator will have flexibility to set the in-market period, but it should be no less than 3 years.

The core final recommendations allow for spot price risk to be effectively managed through the development of derivative contracts suitable for a firmed renewables electricity system. These contracts would be utilised to underpin long-term investment, ensuring that, for the first time since the NEM's creation, a long-term investment signal is economically connected to the medium term which is in turn connected to the spot market (Figure 4).

Figure 4 – Core NEM Review Recommendations at a glance

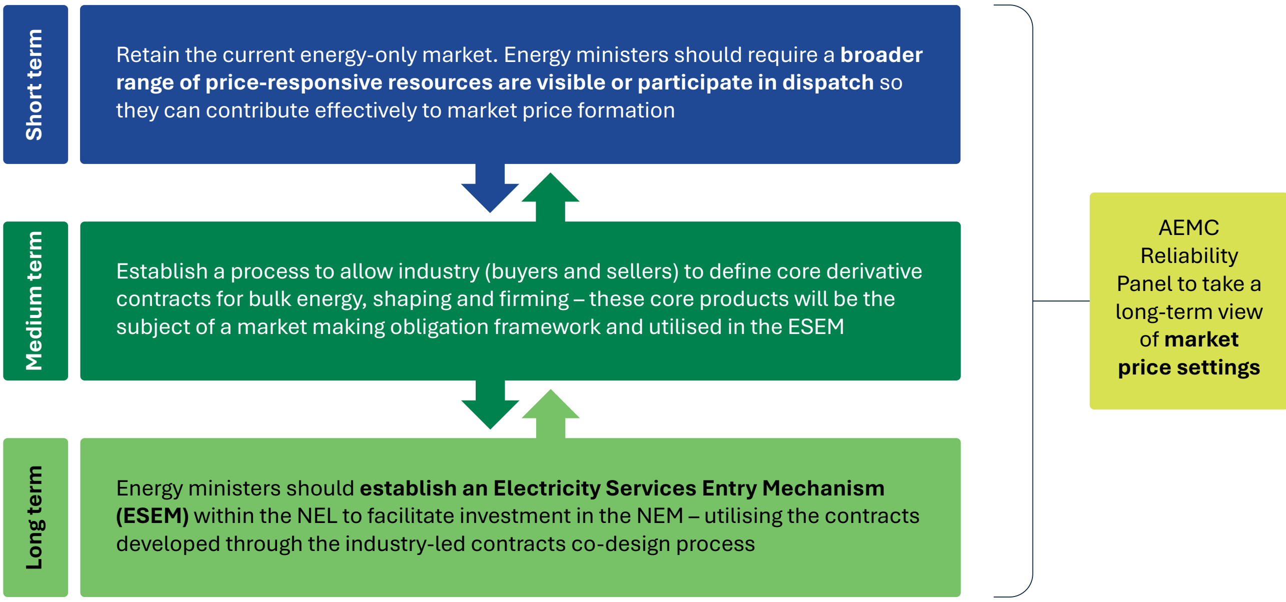
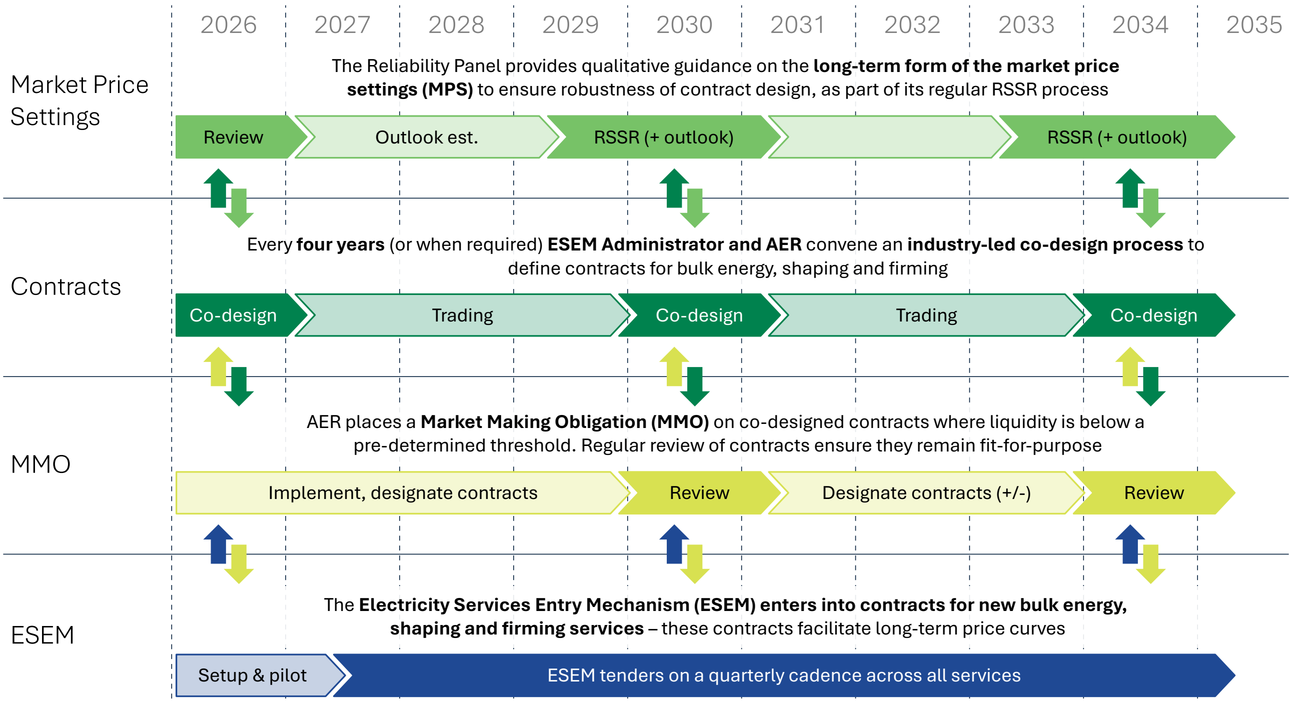


Figure 5 – Interaction and concurrent timing of key recommendations



Untapped potential and unstable prices for consumers

If the challenges facing the NEM are left unaddressed, there is a growing risk that consumers will view electricity markets as a system that no longer serves their interests. As the generation mix becomes more weather dependent and energy constrained, households and businesses may face greater price variability and reduced predictability in their electricity bills if wholesale prices are simply passed through to consumers. The Panel has heard clearly from stakeholders that all consumers want affordable energy, and many also place a premium on price certainty through simple retail offers and stable bills, but the interaction of the retail and wholesale markets is not conducive to retailers offering those outcomes. Without reform, consumers may remain exposed to future fluctuations associated with a changing electricity system.

At the same time, more than three million households and small businesses have taken steps to manage their energy costs by investing in rooftop solar. The uptake of home batteries is accelerating in response to new incentives and falling costs. This period of rapid growth presents a window of opportunity to ensure that these investments deliver benefits to not only individual consumers but to the electricity system.

The Panel's vision for the NEM

Without timely and targeted reform the challenges outlined above are likely to intensify and become entrenched. The Panel's vision is to manage risks so that the NEM has:

- sufficient investment in critical assets and services, managing reliability risks
- the most efficient and stable electricity prices for consumers, as risk premiums reduce and competition thrives
- reduced reliance on ad hoc government interventions, by increasing policy predictability and investor confidence
- a more unified and orderly transition, aligned with the pace and scale needed to replace ageing coal-fired power stations and achieve emissions reduction objectives in an orderly and efficient way.

In considering how to achieve this vision, the Panel has been guided by a clear set of principles. These principles reflect the importance of aligning market reforms with the federated structure of the NEM, preserving the strengths of competitive markets and ensuring that public interventions deliver real and enduring benefits for consumers. Importantly, the Panel believes reforms across the short-, medium- and long-term time frames must be mutually reinforcing and considered holistically.

Figure 6 – Principles for the NEM Review reforms

Align within the federated structure of the NEM

The NEM operates across multiple jurisdictions – Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania – each of which has constitutional responsibility for energy policy. Throughout the history of the NEM these jurisdictions have agreed to nationally harmonise most of the laws that govern the energy market, recognising that a coordinated national framework is essential to avoid fragmentation, duplication or inefficient outcomes. In this respect, wholesale energy market reform should continue to be consistent and harmonised across the NEM, while respecting the sovereignty of jurisdictions to pursue individual policy objectives within that shared framework.

Complement the existing wholesale market

Market interventions should be designed to strengthen, not supplant, the core mechanisms of the NEM. This includes preserving efficient price signals that guide operational decisions and ensuring that new investment mechanisms are integrated with spot and derivatives markets. A well-functioning wholesale market remains central to achieving reliability and affordability, and any additional measures should aim to enhance liquidity and transparency in forward contracting.

Target economic efficiency

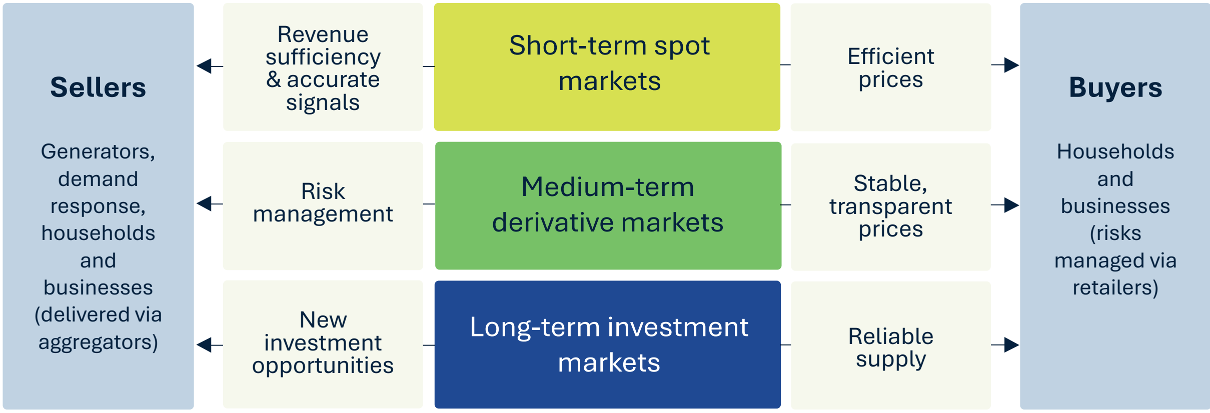
Public interventions should be proportionate and deliver allocatively efficient outcomes. Intervention should only address investment barriers that the market cannot resolve on its own, such as long-term risk allocation, coordination failures, or insufficient price signals, without crowding out private initiative.

Translate into benefits for consumers

Electricity is an essential service for households and a critical input for industry. All reform efforts should ultimately be judged by their impact on consumers. This includes supporting a competitive retail market that enables innovation and choice, while ensuring that consumers and businesses alike can access secure, reliable and affordable electricity. Where government action is required it should be clearly linked to delivering long-term value for the public, with transparent governance and accountability.

The Panel's recommendations seek to work together across the short-, medium- and long-term horizons to uphold the foundational features of a well-functioning electricity market: efficient pricing, effective risk management and reliable supply (Figure 7).

Figure 7 – Features of a successful electricity market for buyers and sellers



The Panel's vision is ambitious but pragmatic. With targeted but consequential reforms, the NEM can operate closer to the original design intent – preserving the benefits of competition while delivering the investment and operational outcomes needed to support a secure, affordable, low-emissions energy future.

Recommendation summary

Drawing on extensive stakeholder consultation and detailed analysis, the Panel has developed a series of recommendations and observations. The Panel has focused on reforms that reinforce the NEM's original architecture and its effectiveness, put the consumer at the centre of the market and uphold the jurisdictional roles of states and territories.

For **sellers** including generators, demand response providers and households and businesses participating via aggregators – the reforms aim to provide accurate price signals, improve access to risk management tools and increase investment certainty.

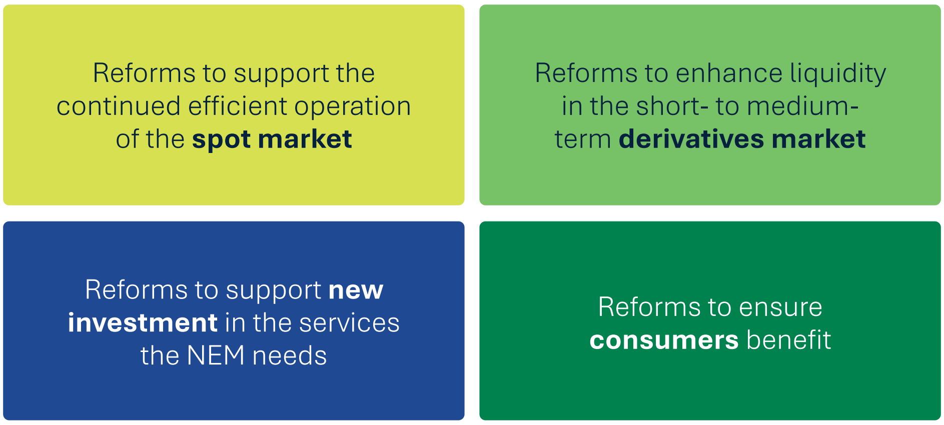
For **buyers** including retailers and commercial and industrial users – the reforms aim to deliver efficient spot prices, stable and transparent contract prices in the derivatives market, and long-term reliable supply.

Most importantly, for all **consumers** both with and without consumer energy resources – the reforms aim to ensure access to reliable electricity at fair, simple and stable prices, and fair rewards for providing services to the system.

Taken together, the Panel's proposed reforms provide a clear and practical pathway towards a more sustainable and efficient energy market – one that preserves the benefits of competition while addressing gaps that have emerged over time.

By improving short-term operational visibility, strengthening the derivatives market, providing long-term investment signals that utilise the derivatives market and engaging in the targeted procurement of essential services that the market is not well placed to provide, the Panel's recommendations will enable the NEM to meet the needs of Australians for decades to come.

Figure 8 – Major recommendation themes



Recommendations

1 Maintain the real-time regional energy-only spot market as the core market for efficient dispatch and rewarding the provision of physical energy services

A. Retain the real-time regional energy-only spot market with necessary rule changes to ensure its continued efficient and competitive operation, recognising that increasing spot market variability and volatility can be managed.

B. Do not create additional mandatory centralised short-term (operational timeframe) markets, such as capacity markets or physical ahead markets.

C. Do not implement locational marginal pricing or variants considered previously.

D. Do not create distribution-level wholesale energy markets. Instead, facilitate distribution-level energy resources to participate in regional markets and use dynamic operating envelopes and dynamic network tariffs to manage local constraints.

2 Energy ministers should require that a wider range of price-responsive resources (PRR) are visible or participate in dispatch so they can contribute effectively to market price formation

A. Energy ministers should implement a mandatory framework for PRR visibility and participation in dispatch. Ministers should give effect to this by:

(i) Tasking the Australian Energy Market Operator (AEMO), in consultation with industry and consumer representatives, to develop by December 2026 a framework that: defines fit-for-purpose visibility modes and their adoption into operational forecasting; establishes thresholds for mandatory participation; and provides advice on consumer benefits and implementation pathways.

(ii) Progressing amendments to the National Electricity Law (NEL) and National Electricity Rules (NER) to enable full implementation of the framework by 2030.

The Panel recommends the framework should apply the following parameters and initial thresholds (within Integrating Price-Responsive Resources zones):

- Portfolio aggregations of small-scale storage (without co-located load) that in aggregate exceed the NER's bidirectional unit (BDU) registration threshold (>5 MW) should be required to participate in dispatch mode (active) or as a BDU.
- Consumer energy resources (CER) portfolio aggregations with remote automated control and an aggregated capacity exceeding the NER's scheduled generation registration threshold (>30 MW), should be required to participate in dispatch mode (inactive), with dispatch mode (active) remaining voluntary. Aggregations below this threshold should provide quarterly reporting to AEMO identifying loads subject to such arrangements.
- Large industrial and commercial loads with aggregated capacity of price-responsive load across their portfolio that exceeds the NER's scheduled generation registration threshold (>30 MW), including those operating under price-contingent demand response contracts, should be required to provide load-intention data to AEMO via a dedicated visibility-only

difference-bid mode or, alternatively, participate through the wholesale demand response mechanism (WDRM).

- Retailers offering pool-price pass-through arrangements or price-contingent demand response contracts, where the aggregated capacity of price-responsive load is below the scheduled generation registration threshold (<30 MW), should be required to submit quarterly reports to AEMO identifying all loads subject to these contractual arrangements.

B. Energy ministers should establish a structured support framework to encourage currently non-scheduled PRR to participate in dispatch mode (active), the WDRM, or as scheduled loads, generators or bidirectional units.

3 Governments should focus reforms and support for CER on facilitating market participation to enable consumers to benefit from being price-responsive

A. Energy ministers should focus the National CER Roadmap on – and ensure sufficient resources are allocated to – delivering the critical roadmap elements that enable market participation (e.g. technical standards) and provide consumer protections.

B. Government incentives for investment in CER, such as for batteries, should support resources that are enabled to participate actively in the market through aggregators and are ready for dynamic network connections.

4 Market bodies should use the rule change process to ensure the efficient and competitive functioning of the real-time energy-only spot market

A. Market bodies and the Australian Competition and Consumer Commission (ACCC) should work together to develop a broader understanding of the risks and opportunities created by algorithmic bidding to inform regulatory responses, including rule changes if needed.

B. Market bodies should analyse whether publishing battery state of charge information from July 2025 adequately mitigates reliability risks or whether further reforms are needed.

C. Market bodies should work to minimise the impact of transmission network outages on the energy-only spot market.

5 The Reliability Panel should consider adjusting the form of the market price settings over time

The Reliability Panel should provide a long-term outlook on the form of the market price settings as an enduring and ongoing responsibility. It should undertake a review in 2026 which provides an initial long-term outlook on the form of the market price settings and the appropriateness of the form of the settings for the future electricity market.

6 Energy ministers should establish a permanent market making obligation (MMO) framework in the National Electricity Law (NEL) and National Electricity Rules (NER) for a small number of key derivative contracts

The MMO framework should include the following key features:

- The MMO framework should apply to contracts for all services (bulk energy, shaping and firming) defined by the industry-led contract co-design process (**Recommendation 7**) and as designated by the Australian Energy Regulator (AER).
- The AER should have the ability to add and remove designated contracts over time, responding to market developments and the outcomes of the industry-led contract co-design process. Initially, the designated contracts for firming services should be caps, and the designated contracts for combined bulk energy and shaping services should be baseload swaps.
- Once a contract is designated, the AER should be responsible for assessing whether the MMO should be triggered for that contract and in which NEM regions. The AER assessment should be based on pre-determined objective liquidity thresholds developed through consultation with industry.[1]
- The AER's decision-making on designating contracts and objective threshold for triggering the MMO for a contract should be informed by consultation with the industry-led contract co-design group (**Recommendation 7**).
- The MMO should be triggered as soon as possible in South Australia. While both caps and baseload swap contracts will be designated, the MMO should initially apply only to cap contracts in South Australia.
- Energy ministers should be able to opt out of the application of the MMO in their region.
- The MMO should cover suppliers of the relevant services in each region that are above a specified threshold, and should set requirements for minimum trading volumes and maximum bid-offer spreads with trading occurring via an AER-approved exchange and/or over-the-counter (OTC) platform.
- Energy trading businesses should also be able to act as voluntary market makers but be required to comply with the same bid-offer spread as obligated mandatory participants if they elect to trade in the MMO windows.[2]

[1] This amended recommendation reflects some stakeholder views that the MMO should only be in place where liquidity is below acceptable levels. In particular, the Panel notes that the industry-led contracts co-design group should provide recommendations to the AER on liquidity thresholds.

[2] The Panel has amended this recommendation in response to stakeholder views that non-physical participants (e.g. energy trading businesses) provide valuable liquidity but should be voluntary market makers to ensure equal market access.

7 The AER and ESEM Administrator should regularly convene an industry-led co-design process to define a small set of core derivative contracts that underpin trading activities and the MMO and ESEM

The industry-led co-design process should occur on a regular basis (e.g. every four years) and include financial market bodies, project developers, brokers, generators, retailers and consumers. The Clean Energy Finance Corporation (CEFC) should be a standing participant of the group.

The first co-design process should occur as soon as practicable, drawing on the findings from the pilot process conducted by the NEM Review Panel.

The contracts developed through the co-design process:

- should be able to be traded on an exchange platform
- should be the subject of market making obligation
- should be able to be traded in smaller parcels to reflect the smaller nature of individual generators (e.g. 100 kW rather than 1 MW)
- should be utilised to contract with projects through the ESEM
- could be used in retail price benchmarking.

8 Energy ministers should commission a review of counterparty risk management and prudential arrangements in the NEM, supported by a multi-agency taskforce and industry subject matter experts

The review should recommend options to improve accessibility and liquidity in derivative markets and increase efficiency of capital deployed as credit support.

9 Energy ministers should make a rule change that extends and publishes the generator availability MT PASA projections from three to five years, to support longer-term derivatives market liquidity and price discovery

10 Energy ministers should establish an ESEM within the National Electricity Law (NEL) and National Electricity Rules (NER) to facilitate investment in the NEM

A. Establish in the NEL and NER an ESEM with the following key features:

- The services initially procured through the ESEM should be: bulk zero emissions energy; shaping; and firming.
- The ESEM should allow new electricity service providers to compete for standardised, fungible contracts developed through the industry-led co-design process outlined in **Recommendation 7**. These contracts would offer stable income streams tied to the delivery of defined electricity services, helping providers finance new projects.

- The ESEM should not address risks that market participants are able to manage. The ESEM Administrator should not issue contracts for the years a project is able to secure them in-market. Rather, the ESEM Administrator should issue contracts for the later years of a project's life, allowing electricity service providers to sell their output to retailers or commercial and industrial (C&I) users for the period of time that the market can manage risks effectively.
- The ESEM Administrator should sell the standardised, fungible contracts it has procured back into the market at the point in time that allows retailers and C&I users to manage energy market risk, supporting retail competition.
- The ESEM Administrator should be open to all providers of a given service (bulk energy, shaping, firming), including aggregators of consumer and distributed energy resources (CER and DER), and demand response providers, provided these resources will be scheduled for dispatch by the Australian Energy Market Operator (AEMO).
- The ESEM Administrator should seek to procure quantities of each service that achieve the National Electricity Objective (NEO). This includes any electricity-sector specific requirements of state and territory government emissions policies referenced in the Australian Energy Market Commission's (AEMC's) targets statement.
- Where specific technologies are required to be procured by state and territory government policy and these technologies face greater barriers than the standard tenor gap (e.g. offshore wind, pumped hydro) the ESEM Administrator should use an amended approach to facilitate their procurement.

B. Where cost-effective, projects facilitated through the ESEM should also be able to provide essential system services (ESS).

C. The ESEM Administrator should apply market concentration thresholds, independently set by the AER, when setting eligibility criteria for participating in ESEM procurement rounds.

D. The ESEM Administrator should facilitate the procurement of strategic reserves covering high-impact, low-likelihood events, with quantities to be procured at the discretion of jurisdictions on advice from the Reliability Panel.

11 Governments and market bodies in the NEM should pursue a coordinated suite of reforms to ensure regulatory settings, the innovation ecosystem and existing policies and programs are aligned with the ESEM

A. Governments should clarify how their greenhouse gas emissions targets apply to projects procured to provide firming services, to provide certainty for investors.

B. The Australian Government should task the Australian Renewable Energy Agency (ARENA), in collaboration with the Clean Energy Finance Corporation (CEFC) and other financiers, to accelerate the development and deployment of zero emissions technologies that provide firming at scale.

C. Governments overseeing existing generation underwriting schemes to support long-term investment should consider options to improve derivative market liquidity.

D. The AEMC should review interconnector hedging arrangements to improve long-term certainty. For example, this could include options to the effect of extending the timeframe for inter-regional settlement residue units beyond three years.

E. Once energy ministers are satisfied the ESEM and market making obligation (MMO) are working effectively, they should phase out the Retailer Reliability Obligation (RRO).

F. Once the ESEM framework is established, energy ministers should consider opportunities to rationalise NEM forecasting and planning documents to avoid inconsistencies and duplication.

G. Energy ministers should pursue reforms to improve consistency in the treatment of load, storage and generators connected at the distribution and transmission level, to ensure a level playing field.

12 Jurisdictions should implement this package of reforms expeditiously, ensuring market bodies are suitably resourced to undertake implementation activities concurrently with legislative processes

1

Introduction to the NEM

Chapter summary

In the 1990s Australian governments embarked on a series of energy market reforms designed to enhance competition, improve efficiency and drive innovation. In 1998 these reforms culminated in the establishment of the National Electricity Market (NEM), creating a wholesale spot market across participating eastern and southern states.

Privatisation of state-owned generation and retail businesses occurred in some jurisdictions, supported in part by vesting contracts to provide transitional revenue certainty. A voluntary derivatives market developed alongside the spot market, enabling participants to manage price risk and promoting investment certainty.

A core feature of the NEM's design is the link between the spot market, which provides short-term price signals for dispatch, and the derivatives market, which is intended to support risk management and long-term investment via price discovery. While the system has functioned well in dispatching electricity efficiently, it has not consistently delivered clear and timely signals for new investment. Rather, new investment has largely been driven by adjacent or complementary government policies.

Retailers play a critical role in this framework, acting as financial intermediaries and managing wholesale price volatility on behalf of consumers. This dual-market architecture remains central to the NEM's operation, though it continues to evolve in response to emerging challenges and the energy transition.

History of the NEM

Defining the NEM: *The term 'NEM' is used in different contexts to refer to different sets of activities – be it activities covered by the National Electricity Rules (NER) and Law (NEL), activities covered by the National Energy Retail Rules (NERR) and National Energy Retail Law (NERL), or complementary activities relating to the derivatives market (including both exchange-traded and over-the-counter (OTC) contracts). For the purposes of this report, the Panel takes a broad definition, with 'NEM' referring to all of the above, including both the spot market (including Frequency Control Ancillary Services (FCAS)), associated derivatives markets and the long-term investment market for new electricity services that will operate in the NEM.*

The NEM is a wholesale electricity market serving Victoria, New South Wales, the Australian Capital Territory, Queensland, South Australia and Tasmania that facilitates the buying and selling of electricity in real time. It is a complex ecosystem that brings together a diverse range of participants to contribute to the production, delivery and use of electricity.

The NEM's 'stringy' network of ~40,000 kilometres of high voltage transmission lines, lower voltage distribution lines and transformers deliver ~180–200 TWh of electricity each year to serve a population of more than 24 million. There are more than 600 registered participants in the NEM, including generators, transmission and distribution network service providers, and market customers (including retailers and large commercial and industrial (C&I) users).

Electricity is a commodity that is produced, dispatched and consumed as a vital service for the end consumer. Consumers (residential and C&I users) are at the heart of the Panel's efforts, considered both as beneficiaries and increasingly as participants of the market's operation, through their choices in retail contracts, engagement in demand response, investment in distributed energy resources and adoption of evolving technology platforms.

Responsibility for electricity policy and regulation constitutionally resides with the states but in practice is exercised in a harmonised way. Through a cooperative legislative framework, the NEM is governed by nationally harmonised laws, particularly the NEL, which is enacted in South Australia and applied in all participating jurisdictions. The NER govern the operation of the NEM and specify everything from the responsibilities of participants to the dispatch of generation and the settlement of the market.

Three statutory market bodies govern the NEM (Figure 9).

Figure 9 – Statutory market bodies in the NEM

Australian Energy Market Commission (AEMC): **the rule-maker**	Australian Energy Regulator (AER): **the regulator**	Australian Energy Market Operator (AEMO): **the operator**
The AEMC is responsible for developing and making the NER and NERR.	The AER is responsible for economic regulation and rules compliance and monitoring the market.	AEMO is the electricity and gas systems market operator, as well as the national transmission planner.

The NEM was established with competition, transparency and efficiency at its core. The formal process to develop the NEM began in 1991 and culminated in the formal establishment of the NEM in 1998. Among other factors, the design of the NEM was influenced by the findings of the National Competition Policy Review chaired by Professor Frederick Hilmer (the Hilmer Review, 1993), which highlighted the inefficiencies of vertically integrated, state-owned electricity businesses and recommended separating monopoly networks from competitive activities like generation and retail. The NEM replaced state-based dispatch processes with a nationally consistent (excluding the Northern Territory and Western Australia), market-based framework for the efficient dispatch and trade of electricity.

The NEM was always intended to work as an integrated system of spot and derivatives markets.[3] This structure was intended to ensure efficient allocation of generation and interstate trade in electricity, with high prices incentivising new generation as needed and sustained low prices encouraging the exit of excess or inefficient capacity. The derivatives market developed organically alongside the spot market and remains essential to its functioning.

The spot and derivatives markets work together to meet demand, manage risk and – at least in theory – provide price signals to support longer-term investment. By design, the NEM's spot market creates sharp price signals for the dispatch of least marginal-cost plant to meet required demand and encourage generators to be available during times of scarcity. In turn, anticipation of future spot prices forms the basis of forward derivative contracts, which should provide price signals for future entry or exit of generating plant into or out of the system. In a well-functioning wholesale market, the spot and derivatives markets work in tandem to provide signals for efficient dispatch and timely investment – and ultimately affordable and reliable electricity for consumers. This is shown in Figure 10 and Figure 11.

[3] Council of Australian Governments (2002), Towards a truly national and efficient energy market: Final report of the Council of Australian Governments Energy Market Review, p 23.

Figure 10 – The NEM connects the physical and financial electricity system across three time horizons

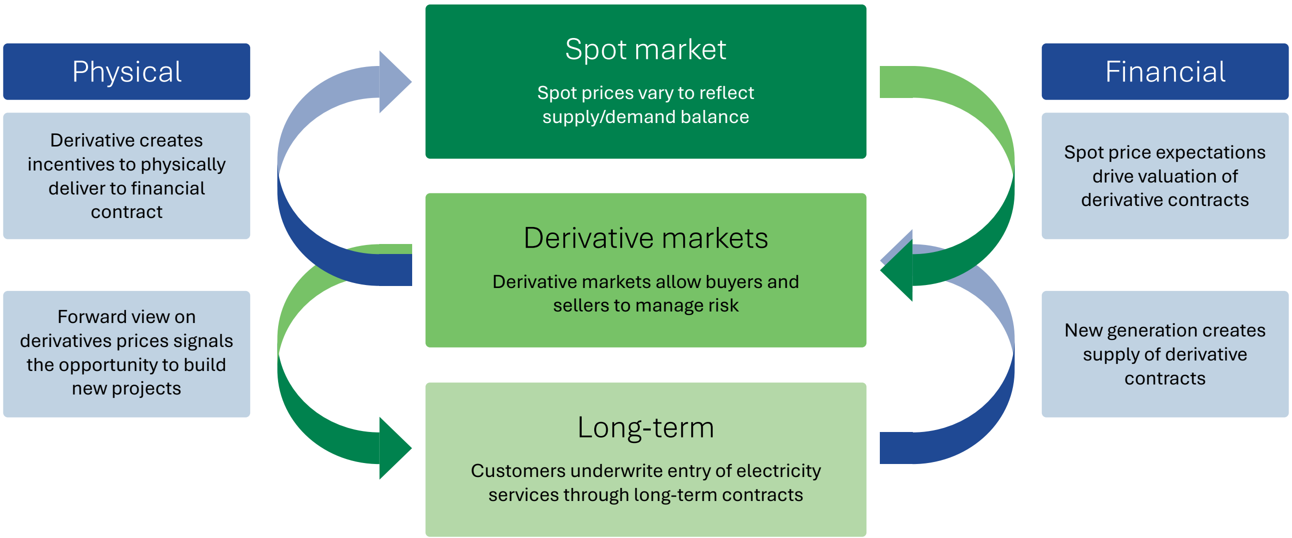


Figure 11 – How the NEM was intended to work

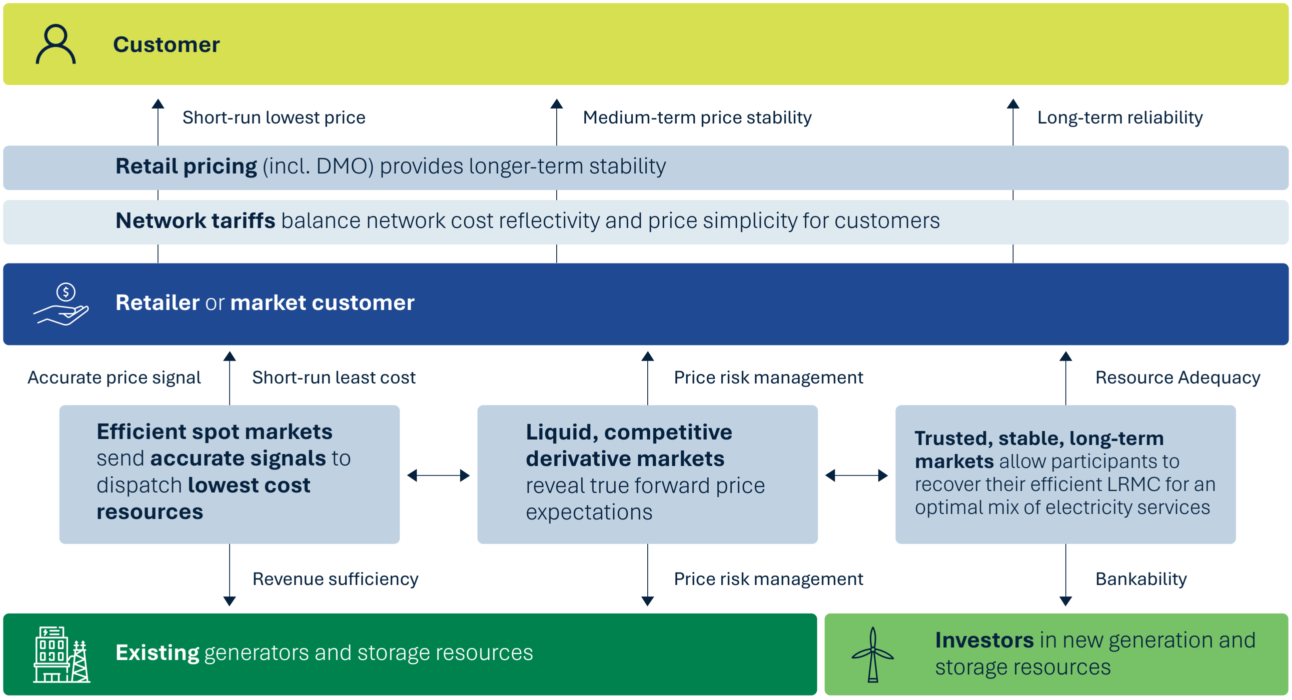


Figure 12 – Timeline of development of spot and derivatives markets in the NEM

Pre-1990s

State electricity commissions controlled all aspects of the electricity supply chain, including retail, generation, transmission, and distribution. Planning and investment decisions were driven by state objectives and generation was built by Governments to take advantage of local fuel sources such as brown coal in Victoria, black coal in Queensland and New South Wales, and hydro generation in Tasmania.

1991

Council of Australian Governments (COAG) agreed to establish a National Grid Management Council (NGMC) to coordinate the planning, operation and development of a competitive electricity market.

1992

The Australian Government commissioned the National Competition Policy Review (Hilmer Review), which highlighted the inefficiencies of vertically integrated, state-owned electricity businesses and recommended separating monopoly networks from competitive activities like generation and retail (with the separation of these activities generally occurring much later).

1994

In Victoria, large industrial customers were made contestable and the wholesale market VicPool was established. The State Electricity Commission of Victoria was disaggregated into separate transmission, generation and retailer/distributor businesses, laying the groundwork for privatisation.

1995

The first privatisations of Victorian electricity businesses occurred as the Kennett Government sought to increase efficiency.

1997

The National Electricity Market Management Company (NEMMCO) was established to manage the planned transition to a national wholesale market.

1998

The National Electricity Market (NEM) officially commenced, replacing VicPool and the NSW pool. State electricity corporations began to be split into separate generation, network and retail businesses.

1999

Privatisation of the electricity sector in South Australia commenced.

2002

Full retail competition introduced in Victoria and New South Wales. The Sydney Futures Exchange was relaunched and began offering standardised electricity futures contracts (incl. 1 MW flat and peak swaps). These were co-designed by market participants, addressing the shortcomings of previous offerings.

2003

Full retail competition extended to South Australia.

2004

The Sydney Futures Exchange introduced caps and options, expanding the range of hedging tools available.

2006

The Sydney Futures Exchange merged with the Australian Securities Exchange. Queensland sold its south-eastern retail electricity businesses.

2007

The volume of exchange-traded electricity derivatives rose dramatically year-on-year. Full retail competition introduced in Queensland.

2008

Following a review by the AEMC, the Victorian government removed all retail price controls, allowing retailers to set their own prices.

2010

New South Wales began the gradual privatisation of its electricity generation and retail businesses.

2013

South Australia deregulated its retail electricity prices.

2015

New South Wales deregulated retail prices.

2016

Queensland deregulated retail prices.

2017

Australian Competition and Consumer Commission (ACCC) Inquiry into retail supply of electricity and competitiveness of retail electricity markets, with key recommendations for retail electricity pricing focused on enhancing consumer choice and lowering costs.

2019

Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (AER) legislation was introduced to set out the legislative framework for the Default Market Offer (DMO). Victorian Essential Services Commission introduces Victorian Default Offer (VDO).

The role of the wholesale spot market, derivatives market and ancillary markets

1.1. The spot market provides transparent price signals for real-time dispatch and system balancing

The NEM Dispatch Engine (NEMDE) runs the complex dispatch process, selecting the lowest cost combination of generator and load offers to meet demand across the NEM subject to the technical constraints of the power system. The output from NEMDE is a set of regional electricity 'pool' prices and dispatch instructions for generators and loads. Generators are paid the regional pool price for the energy they produce and retailers and other market customers must pay the regional pool price for the energy they consume in that region. AEMO manages the settlement of the market to ensure the financial integrity of the system.

Figure 13 – Key features of the wholesale spot market

Energy only

Generators are paid only for the electricity they produce and sell into the market, with no separate payment for simply being available. This model relies on scarcity pricing to ensure sufficient investment in generation: during periods of tight supply, prices can spike to very high levels (up to the market price cap), providing a return on capital intensive investments for flexible and reliable generation. This approach creates a strong link between actual supply and financial reward, encouraging efficient operation and investment.

Mandatory, gross pool

Generators (above a threshold) are required to bid into the market and be dispatched but are only paid for the actual electricity they provide and deliver, with spot prices determined by supply and demand at five-minute intervals. The supply curve for electricity depends on which generators are available and what their costs are. Demand is forecast by the market operator and has historically been inelastic in the short-run.

Real time

Generators are responsible for self-commitment and there is no day-ahead schedule. While AEMO retains residual powers to ensure that the power system balances, it is generators who are primarily responsible for monitoring market information and being ready to meet the power system requirements.

Uniform clearing price

All generators that are dispatched receive the same market price. The price is set by the highest-priced (marginal) bid required to meet demand in each five-minute interval. This model encourages generators to bid their true marginal cost. This leads to greater market efficiency and transparency. Uniform-clearing also facilitates liquid derivatives markets which are important for managing spot price risks.

The spot market is supported by a suite of mechanisms to manage system security and market volatility, including price caps and floors and AEMO's intervention powers.

1.2. The derivatives market provides generators and retailers with the ability to manage spot price risk

While price volatility in the spot market sends important scarcity signals to support dispatch, it creates significant financial risks for retailers, who cannot pass on high prices to customers in real time, and generators, whose revenues are vulnerable to low spot prices. The derivatives market operates alongside the wholesale spot market and enables participants to manage the financial risks arising from volatility in the spot market. Importantly, the derivatives market allows the value of firm capacity to be effectively priced. In this way, derivatives markets facilitate a decentralised capacity market within the NEM.

Figure 14 – Key features of the NEM derivatives market

Non-mandatory

Parties are generally not required to participate.

Financial, not physical

Contracts do not involve physical delivery of electricity. Instead, they involve financial settlements based on the difference between agreed strike prices and realised spot prices. Common contract types include swap contracts and cap contracts.

Decentralised

Contracts are struck bilaterally (over-the-counter (OTC)) or through exchanges (ASX futures exchange or FEX Global). Exchange-traded products are standardised and transparent. OTC products are more bespoke and less transparent (although recent reforms empower the AER to collect and publish OTC trade data for the first time[3]).

Forward-looking

Contracts are typically struck months or years in advance of delivery, and can cover a range of products. These instruments allow market participants to lock in prices and manage exposure to volatile spot price outcomes.

To be effective, the derivatives market must facilitate price discoverability, with transparent price signals that reflect market conditions and future expectations. It must also have enough competition and liquidity so that contracts can be bought and sold easily at reasonable prices. Derivatives markets should also provide for anonymous trading to avoid potential market discrimination.

Well-functioning derivatives markets can also provide forward price signals to support new investment. Rising contract prices signal expected scarcity and can incentivise investment; falling prices may lead to plant retiring or mothballing. However, the derivatives market's ability to inform efficient investment and retirement decisions is limited when it does not function as intended. This is important given the tenor gap the Panel has identified in relation to supplier and buyer misalignment around contracting appetite for future periods (see **Chapter 2: Trends and challenges in the NEM**).

Retailers buy energy from the spot market to meet their contracted customers' demand. The risks retailers face include volume risk, price differential risk, credit risk and prudential risks. Retailers have typically managed these risks by either buying hedging contracts (to shift wholesale price risk to another party) or investing in generation to balance earnings across the generation and retail arms

[4] DCCEEW (2024), Amending the Australian Energy Regulatory Wholesale Market Monitoring and Reporting Framework.

of their business. While vertically integrated retailers are less reliant on external contracts, they still participate in the derivatives market to manage residual risk. Some large C&I users also hedge directly, either via financial intermediaries or by entering into long-term power purchase agreements (PPAs) with renewable energy developers as part of their broader decarbonisation and cost management strategies.

Generators supply energy into the market to meet regional electricity demand. Generators face several risks, including price risk, fuel price risk, congestion risk, marginal loss factors (MLFs) and technical and regulatory risks. Variable renewable generators face specific risks relating to resource availability and green certificate price risk, and storage operators face risks around price spread and arbitrage risks, degradation and operational risks and ancillary services market risks. Like retailers, generators and storage operators have managed these risks with several strategies, including through the careful design and operation of plant, vertical integration, selling contracts to intermediaries, retailers or C&I users, or participation in government underwriting or revenue-sharing schemes (such as the Capacity Investment Scheme and New South Wales Long-Term Energy Service Agreements).

Figure 15 – Types of risks faced by retailers and generators in the NEM

Retailer risks

- **Volume risk:** Customer demand is higher or lower than forecast, leaving the retailer 'short' or 'long' relative to their contracted position.
- **Price differential risk**: Spot prices exceed the retailer's contracted price but they cannot pass through the higher cost to customers.
- **Credit and prudential risk:** Retailers must post collateral with AEMO and may face losses if customers default on bill payments.

Generator and storage risks

- **Spot price risk:** Generators may not recover costs if spot prices are low and they are 'long' relative to contracted volumes.
- **Fuel price risk (thermal):** Exposure to volatile prices in coal, gas, or diesel fuel markets.
- **Congestion risk:** Output may be curtailed if located in a congested part of the network.
- **MLF risk:** Generators located far from demand centres may earn less due to energy losses on the transmission network.
- **Technology and regulatory risk:** Changes in policy or technology may erode the competitiveness or viability of existing assets.

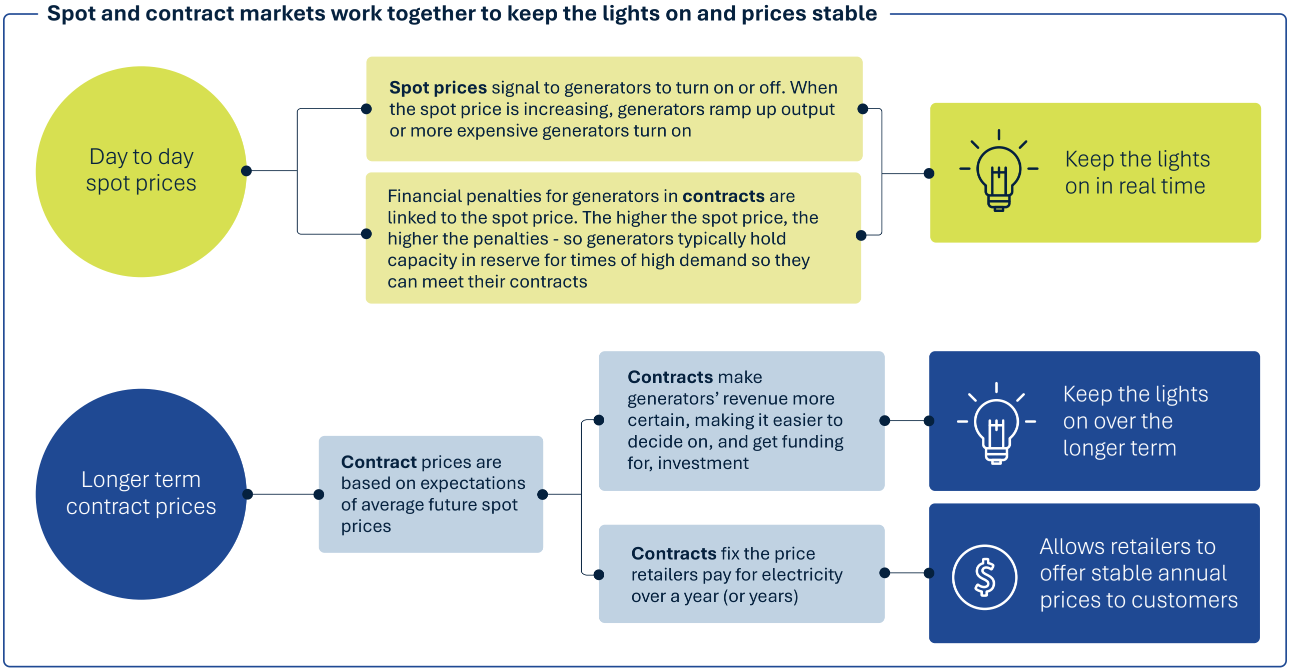
Variable Renewable Energy–specific risks

- **Resource availability risk:** Output is dependent on the availability of wind, sunlight or water.
- **Certificate price risk:** Exposure to changes in the price of renewable energy certificates if not contracted under a PPA.

Storage-specific risks

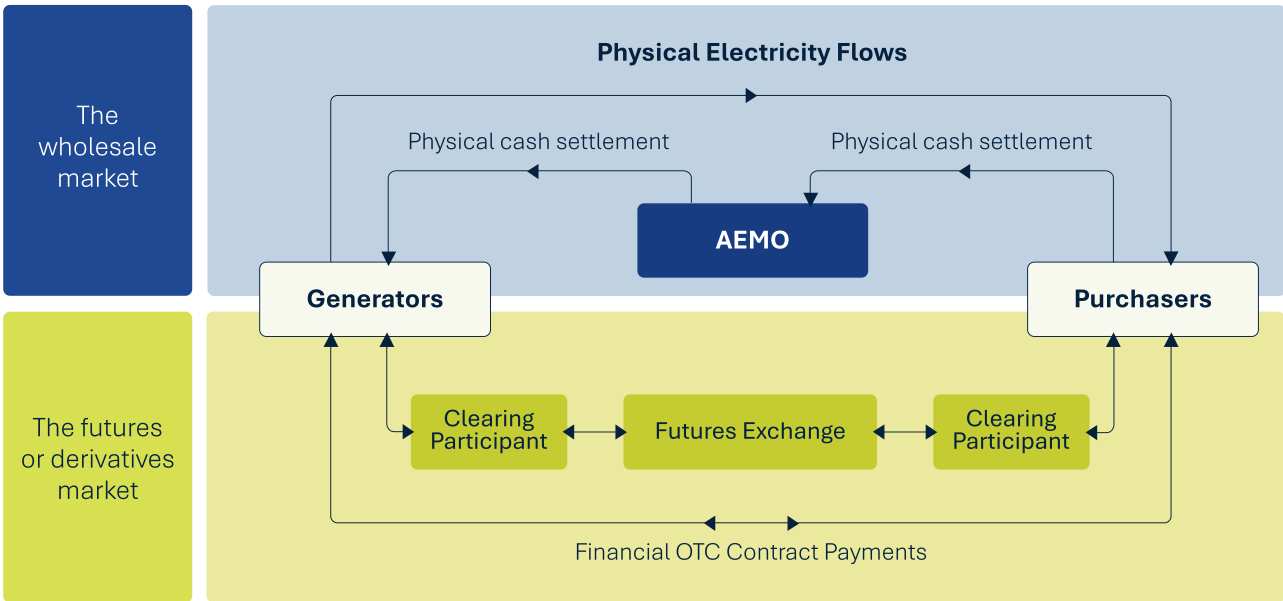
- **Arbitrage and price spread risk:** Profitability depends on capturing sufficient price differentials between charging and discharging, accounting for round-trip losses.
- **Degradation and operational risk:** Frequent cycling and deep discharge can shorten battery life, requiring careful optimisation.
- **Ancillary services market risk:** Revenues from services like frequency control can be uncertain and variable.

Figure 16 – How the spot and derivatives (contract) markets work together



Source: Adapted from [AEMC spot and contract markets webpage]

Figure 17 – Physical and financial flows in the NEM and associated derivatives markets



1.3. Essential System Services are fundamental to maintaining real-time system stability

Ancillary markets in the NEM primarily serve as mechanisms to procure certain essential system services (ESS). The secure and reliable real-time operation of the NEM depends not only on having sufficient generation (managed through the wholesale spot market) and financial tools for participants to manage risk (through the derivatives market) but also on a suite of technical capabilities known as ESS.

Figure 18 – Key ESS in a high inverter-based resource environment

Frequency control

Ensures frequency remains close to 50 Hz. Continuous “regulation” frequency control adjusts generation or load every four seconds, while “contingency” and newer “fast frequency response” services inject or withdraw power within seconds after a major disturbance.

Inertia

Slows the rate of frequency change during disturbances, providing immediate resistance through kinetic energy stored in spinning machines or emulated by grid-forming inverters.

System strength

Refers to the system's ability to maintain stable voltage and rapidly recover after disturbances, indicated indirectly by measures such as fault levels or Short-Circuit Level.

Voltage control and reactive power

Helps maintain system stability and efficiency by managing voltage levels. As electricity flows through transmission lines and transformers, they consume reactive power, which causes voltage to drop. To counter this, injecting reactive power increases voltage, while absorbing reactive power decreases it.

Reserves

Extra capacity called on by the system operator in response to forecast demand spikes or generation shortfalls outside normal expectations, which can be used as a last resort when other mechanisms fail. This extra capacity can be procured out-of-market via the Reliability and Emergency Reserve Trader if shortfalls arise.

System restart services

Facilitates the restoration of electricity supply following a major supply disruption. Generators capable of independent operation (starting without external power from the network) form the foundation of this process.

Under the NEL, AEMO is responsible for maintaining power system security and ensuring the availability of ESS in real time. AEMO directly contracts some services, such as network support and control ancillary services (NSCAS) and system restart ancillary services (SRAS), while markets have been developed within the NEM dispatch architecture for others, such as frequency control ancillary services (FCAS). Services including inertia and system strength have only recently begun to attract attention as traditional sources (such as coal-fired plant) retire. Historically, these services were effectively provided as byproducts of large synchronous generators, such as coal, gas and hydro, and did not require explicit procurement or pricing.

There are dedicated markets for FCAS, with all other services procured through bilateral contracts. Ancillary service costs are recovered from market participants through a regulated cost allocation framework.

Figure 19 illustrates the different roles that AEMO and transmission network service providers (TNSPs) hold in providing ESS in the NEM.

- **Frequency Control Markets:** There are 10 FCAS markets, covering regulation and contingency services, designed to correct deviations in system frequency. Participants bid to provide these services and are paid both for being available and for delivering a service when called upon. As with the spot market for energy, bids are co-optimised within the NEMDE, which selects the least-cost combination of services subject to system constraints. This ensures frequency stability at lowest cost to the system.
- **Contracted Services**: For other essential services not suited to market-based procurement, AEMO enters into agreements with providers. These include NSCAS, used to maintain power flows and voltage within limits, and SRAS, which enable the re-energisation of the grid following a blackout.

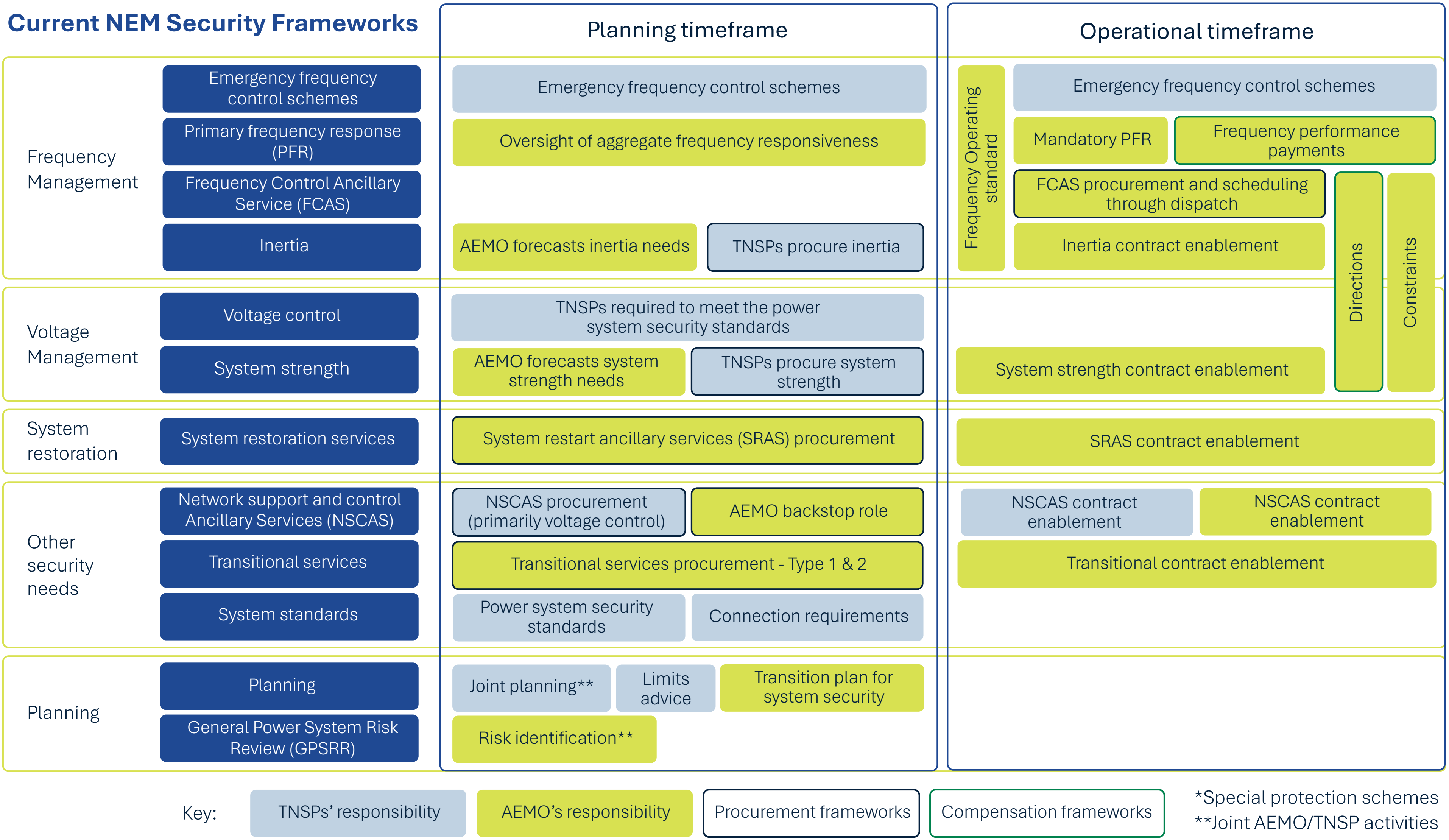
These markets and contracts operate alongside the spot market, forming a complementary set of mechanisms to ensure that electricity is delivered securely and reliably.

TNSPs assist AEMO by procuring and providing system strength services under contractual arrangements consistent with AEMO's requirements. The AER then determines appropriate cost recovery. Specifically, TNSPs have two key obligations:

- When AEMO identifies a gap in system strength or inertia through a declared NSCAS need, the TNSP must address that gap. If the required works must be delivered within 18 months, the associated expenditure is exempt from the Regulatory Investment Test for Transmission.[5]
- From 2 December 2025, TNSPs that are also designated as 'system strength service providers' must deliver an efficient level of system strength and ensure that AEMO's required three-phase fault levels are maintained at each declared system strength node.[6]

[5] NER, cl. 5.16.3(a)(10).
[6] AEMC (2021), Rule determination: National electricity amendment (efficient management of system strength on the power system) Rule 2021, p 15 ; AER (2024), The Efficient Management of System Strength Framework: AER Guidance Note, p 7.

Figure 19 – Roles and responsibilities of AEMO and TNSPs in ESS planning and procurement



Source: Adapted from AEMC presentation *[Update on AEMC reform work program ESS & system security in March 2025.](#)*

1.4. The transmission network remains fundamental to the efficient functioning of the NEM

While transmission planning and investment frameworks are specifically out of scope for this review, the transmission network remains fundamental to the efficient functioning of the NEM. The NEM's 40,000 kilometres of transmission lines connect generators to major load centres and enable electricity to flow between states through interconnectors. Key features of the transmission network include:

- **Open access and cost allocation:** Under the NEM's open access regime, generators may connect to the network provided they meet technical standards and fund their connection infrastructure. They do not pay for ongoing use of the shared transmission system. Instead, those costs are recovered from consumers. This arrangement encourages investment in generation but does not guarantee generators receive unconstrained access to the market. It is worth noting, New South Wales's Access Scheme diverges from this principle by allocating access rights in Renewable Energy Zones (REZs).
- **Interconnection and regional pricing:** The NEM is divided into five regions, each with a designated Regional Reference Node. Spot prices are calculated at these nodes and reflect local supply-demand conditions. Interconnectors link the regions, allowing electricity to flow from lower- to higher-priced regions, helping to moderate prices and improve reliability. However, when interconnectors reach capacity, regional prices separate, potentially leading to sharp price differences for market participants operating across regional boundaries.
- **Losses and congestion:** Electricity is lost as it travels long distances. These losses are captured through MLFs which adjust a generator's market revenue to reflect the actual value their electricity delivers to the system. MLFs are updated annually and can vary depending upon anticipated power flows from new loads and generators. In addition, transmission congestion can occur when physical limits on the network prevent the lowest-cost generation from being dispatched. When this happens, some generators are 'constrained off' and higher-cost local generators may set the market price.

Centralised, long-term planning is essential to ensure transmission investment occurs in the right places, at the right scale and with sufficient lead time. The shift to a zero-marginal-cost system increases the need for some level of coordinated planning and policy direction to overcome persistent network constraints and ensure system reliability and efficiency. While market-based mechanisms like locational marginal pricing and financial transmission rights (FTRs) have been previously considered as a potential solution, they have not been implemented as they cannot, on their own, deliver the long-term, capital-intensive transmission investments required to support a renewable-dominated system. The Panel notes that in other markets globally FTRs are not issued over investment timeframes and are instead only provided for one to three years into the future.

State governments within the NEM have increasingly stepped in to coordinate transmission investment through mechanisms such as REZs. These zones bundle generation and transmission planning into a single framework, allowing governments to strategically identify areas with high renewable resource potential and then coordinate the necessary network upgrades to unlock that capacity. By doing so, states are effectively bypassing the uncertainty and delays associated with market-led transmission development.

1.5. Retailers play an important role as matchmakers and risk managers in the NEM

Retailers serve as the interface between wholesale markets and consumers, managing price risk and tailoring products to customer needs. Since the market's inception, the regulatory framework for retailers has evolved, moving from highly regulated structures to widespread deregulation in the 2000s aimed at promoting competition and consumer choice, and more recently back towards stronger oversight. Growing concerns about affordability and market complexity led to the introduction of the Default Market Offer in 2019, which seeks to provide clearer reference pricing and protections for consumers. Ongoing reviews by the Australian Competition and Consumer Commission reflect a continued focus on ensuring the retail market remains competitive, transparent and responsive to consumer outcomes.

Vertical integration has led to the rise of 'gentailers' like AGL, Origin and EnergyAustralia. A second tier of gentailers has more recently emerged, including Alinta, ENGIE, Snowy/Red-Lumo and Hydro Tasmania/Momentum. Today these combined gentailers serve more than 80% of consumers in the NEM.

The retail landscape has evolved as competition has increased. According to the AER, the retail landscape, previously dominated by the three Tier 1 retailers (AGL, Origin Energy and EnergyAustralia) now has over 52 active electricity retailers servicing over 6.8 million consumers. Since 2019–20, Tier 1 retailers have lost 2.9% of their market share to Tier 2 retailers.[7] Tier 2 retailers have been observed to provide a wider range of both extremely high- and low-priced offers, and their participation has been attributed to an increase in consumers on market offers.

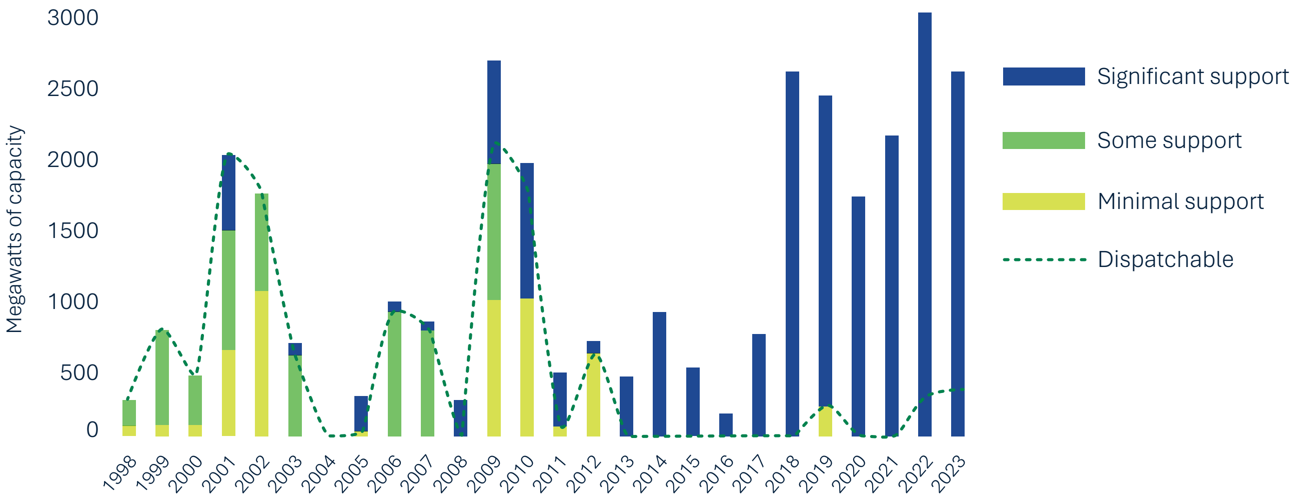
1.6. Investment in new generation in the NEM has been uneven – and in large part driven by specific policy measures

Investment in new generation in the NEM has fluctuated significantly over time, both in scale and by technology type. These shifts can be broadly grouped into three distinct periods since the market's inception: a phase of growth driven primarily by rising peak demand (1998–2011); a period of oversupply and limited new investment outside of renewables mandated by the expanded Renewable Energy Target (RET) (2011–15); and the current phase of transition towards a low-emissions system (2015-present) (see Figure 20).

Although the design of the NEM aimed to let market forces drive investment decisions, government policy support has been a significant driver of investment in new generation since its inception. The Panel notes that this has been a feature of most deregulated electricity markets, irrespective of the market design adopted. Almost all investment in new generation capacity in the NEM has received some form of government policy support, and there are very few examples of pure, market-only investments that were made entirely on the basis of expectations about future spot market revenues and forward derivatives markets. Emerging research suggests NEM spot prices and derivative markets on their own have not driven recent investment decisions in the NEM, in contrast to the strong role of policy support.[8]

7 AER (2024), Annual retail markets report 2023–24, data workbook.
8 Csereklyei & Say (2025), Quantifying the effect of energy policies on electricity generation investments in Australia's National Electricity Market, presentation at NEM Review 'Lunch and Learn', 6 June 2025.

Figure 20 – Generation build by non-market support, 1998 to 2023



Sources: NEM review analysis drawing on AEMO Generation Information, Bloomberg New Energy Finance, and the work and expertise of a range of experts. Includes utility scale generation from coal, gas, solar, wind, hydro. Excludes batteries, pumped hydro, rooftop solar or other small-scale resources, and demand side participation.

Periods of investment in the NEM

1998 to 2011: Growth

The NEM's early years saw strong growth in peak electricity demand, especially in Queensland. This drove significant investment in new generation capacity, particularly black coal in Queensland (Callide C, Milmerran, Tarong North, Kogan Creek) and gas generators (Oakey, Swanbank E, Braemar, Darling Downs).

Several factors supported this growth, including rising peak demand from air conditioning and economic growth, availability of long-term, low-cost coal or gas contracts, public investment via government business enterprises, and vertical integration by gentailers. National and state-based schemes also supported this growth, including the introduction of the Mandatory RET in 2001, the NSW Greenhouse Gas Abatement Scheme (GGAS) in 2003 and Queensland's Gas Scheme in 2005.

2011 to 2014: Oversupply

This period saw falling grid-based electricity demand driven by significant changes in industrial load with the closure of smelters (Kurri Kurri and Point Henry), as well as energy efficiency measures and the growth of distributed solar PV. Simultaneously, industrial demand shifted with LNG developments in Queensland. The result was market oversupply, and AEMO's 2014 Electricity Statement of Opportunities (ESOO) identified that no new generation was needed in any region.

Policy uncertainty further dampened investment: the Carbon Pollution Reduction Scheme was introduced in 2012 and then repealed in 2014, the RET was split into the Large-scale RET and the Small-scale Renewable Energy Scheme, and the GGAS and Queensland Gas Scheme were wound down. Although some renewables were built, investor confidence was weak.

2015 to present: Transition

From 2016 grid-based demand in the NEM remained flat due to rooftop solar despite industrial load increases. This period saw the onset of a renewable investment boom driven by the RET. Major thermal closures included Northern (2016), Hazelwood (2017) and Liddell (2023).

Government investment increased (e.g. Snowy 2.0, Hunter Power Project) and new state-based mechanisms emerged. The NSW Electricity Infrastructure Roadmap (2020) and Commonwealth Capacity Investment Scheme (2022) introduced new investment models involving tenders and long-term contracts.

2

Trends and challenges in the NEM

Chapter summary

Any review of electricity market design must consider emerging trends and challenges. This chapter does not attempt to predict the precise shape of the future National Electricity Market (NEM) – other planning and forecasting documents are better placed to do this. Instead, it outlines the most important drivers of change and considers the implications for how the market functions.

Put simply, the key trend shaping the NEM is technological change. When the NEM was established, Australia's electricity system was powered predominantly by coal, gas and hydro. That foundation is now shifting in response to the need to decarbonise and modernise the electricity system. Variable renewable energy (VRE), particularly wind and solar, is likely to provide the bulk of Australia's electricity. This is likely to be firmed by batteries, pumped hydro and gas, with energy shifted to the times it is needed most. Consumers are likely to play a more complex role: millions of households and businesses are likely to not only consume energy but also increasingly produce, store and manage it, contributing actively to the system's supply and flexibility.

This shift brings challenges. Electricity supply is becoming more weather-dependent, more energy-constrained, less visible to the Australian Energy Market Operator (AEMO) and less able to deliver essential system services (ESS) in the way that large synchronous generators once did. At the same time, consumer behaviour is evolving in ways that introduce new uncertainties for forecasting demand and market operation.

These changes will test the NEM's existing structures across three key horizons:

- In the **spot market** increasing variability and volatility in supply and demand impede price formation without resources being visible. Forecasting and efficiency will improve if more market resources become visible and participate in dispatch.
- Price variability and volatility increases the importance of **derivatives markets**, which allow market participants to manage risk. If liquidity in these markets increases investor confidence and retail competition will improve.
- The current market design provides incomplete incentives to support **long-term investment** in the resources the future system requires, particularly assets that: provide bulk energy; shape and match supply and demand; provide longer-term firming of generation during periods of scarcity; and provide ESS after ageing generators are retired. Addressing the tenor gap between the short-term nature of derivatives markets and the long-term financing needs of capital-intensive projects will be central to achieving investment at the pace and scale required.

The NEM has never been a set-and-forget system. Instead, it has evolved steadily to meet new challenges and will continue to do so. By identifying the most influential trends and designing reforms that can accommodate a wide range of technological changes, the Panel seeks to position the NEM for long-term success.

Technological changes

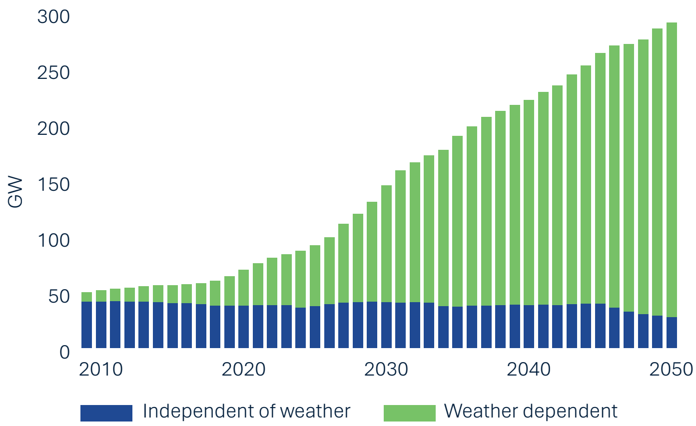
Generation technology in the NEM is changing, driven by the need to decarbonise the economy and modernise electricity systems as existing plant reaches the end of its useful life. This change is fundamentally reshaping the market. The step change scenario of AEMO's 2024 Integrated System Plan (ISP) reflects most of these anticipated changes – a shift towards supply that is less scheduled, more dependent on weather and more energy-limited.

The figures below use the ISP's capacity projections to show how these changes will affect the NEM under current policy settings.[9]

Figure 21 – Changing characteristics of generation in the NEM[10] [11]

Increasingly weather dependent

The growth of variable renewable energy (VRE) will increase the electricity system's dependence on weather. This heightens supply and demand risks but also creates a market for shaping (storage, demand response) to spread demand across the day, and for firming resources. VRE variability will increasingly drive intraday, seasonal and annual price volatility. As a result, risk-management tools will become more important for generators, retailers and commercial and industrial (C&I) users to manage the risks – physical and financial – of buying and selling electricity.



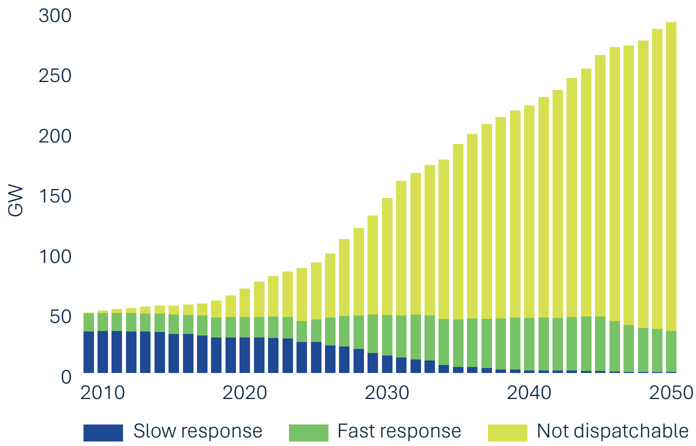
[9] The capacity projections in Figure 21 exclude demand-side participation and assume that projections of 'coordinated' consumer energy resources (CER) storage will remain unscheduled without reforms. **Chapter 3: Ensuring effective operation of the spot market** discusses the reforms needed to encourage CER visibility and participation in dispatch. Sources: AEMO 2024 ISP data, NEM Review analysis.

[10] NEM Review analysis based on AEMO 2024 ISP data.

[11] IES (2024), Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, final report to AEMO, p 7–8.

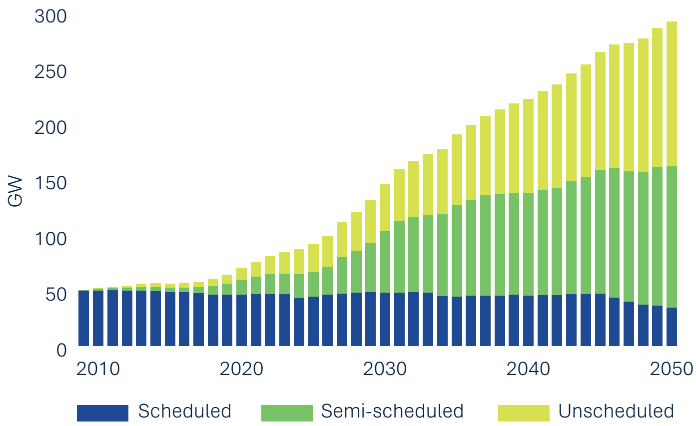
Less dispatchable capacity

New dispatchable generation will be required to provide shaping and firming services when VRE is scarce.



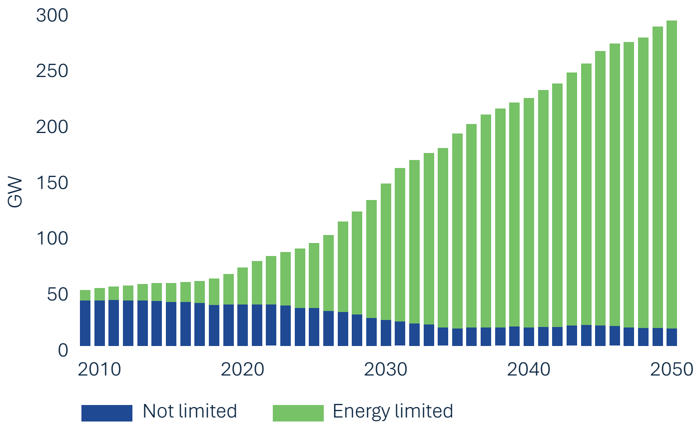
Less visible and less scheduled resources

Distributed consumer-owned resources, such as home solar and battery systems, will provide an increasing share of capacity. If price-responsive resources, such as virtual power plants (VPPs) are not participating in the market, AEMO's demand forecasts may become less accurate, reducing market efficiency and jeopardising grid stability. Without visibility of these resources, there is a significant risk of over-building large-scale resources. It is estimated this could result in $1.4 billion to $1.8 billion of extra unnecessary costs.[11]



Energy limited

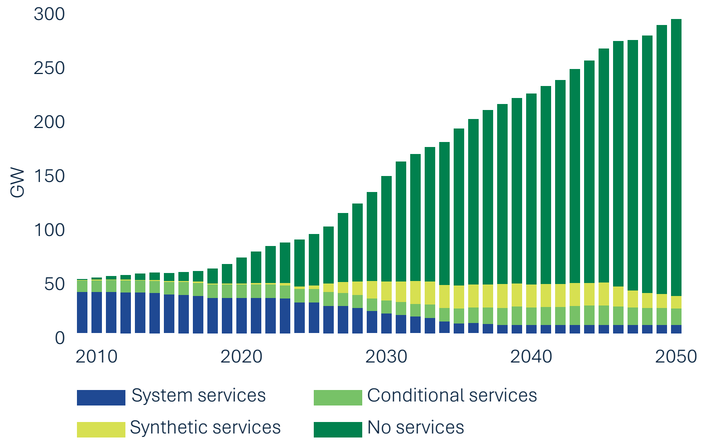
The growing reliance on 'energy-limited' plant – such as VRE (limited by weather dependence) and batteries, hydro and pumped hydro (limited by storage capacity) – highlights the need for long-duration firming capacity and reserves to support the NEM during prolonged periods of low wind and solar generation.



[12] IES (2024), Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, final report to AEMO, p 7–9.

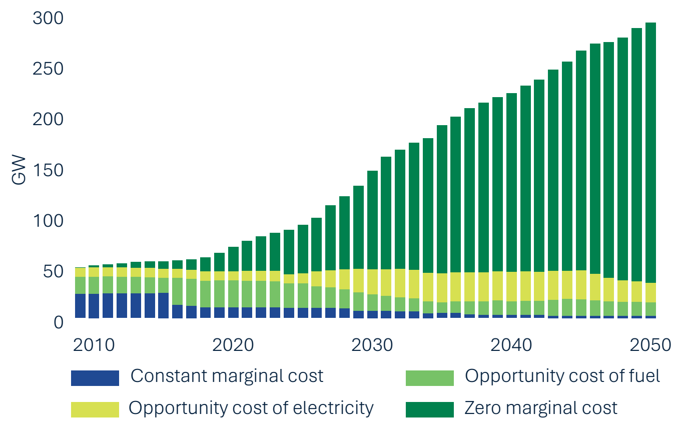
Less able to provide essential system services

Coal-fired power stations have provided many of the essential engineering services the grid needs to operate securely, such as system strength and inertia. To keep the grid running smoothly as we shift to other forms of bulk energy, shaping and firming, we need new technologies that do this. This includes machines that can operate as synchronous condensers, grid-forming inverters and other smart solutions. Encouraging investment in the most cost-efficient alternatives will help to secure the future energy system.



Changing nature of marginal costs

Price-setting in the spot market will continuously evolve as generation technologies change. Thermal power stations (black coal, gas and diesel, but not brown coal or mine-to-mouth coal) are exposed to international fuel markets, which affect their marginal costs. The opportunity costs of storage – electricity prices at other times of the day – may increasingly set spot prices during demand peaks and periods of low VRE generation. Today these opportunity costs are strongly influenced by global gas markets. VRE, with no effective opportunity cost, may set prices at other times.



Implications for the wholesale spot market

NEM prices rise and fall in line with supply availability and demand fluctuations. However, the physical changes to generation are changing these price dynamics. The barriers to efficient spot market operation and price formation are expected to become more acute, with the NEM characterised by a growing number of hidden resources, an increased need for AEMO to intervene in the market to maintain grid stability and persistent uncertainty around future demand. The Panel notes that many stakeholders expect to see spot price signals sharpening, operational price forecasts becoming less accurate and gas continuing to play a role in price formation at certain times of the day and year.

2.1 Prices will become predictably more variable and unpredictably more volatile

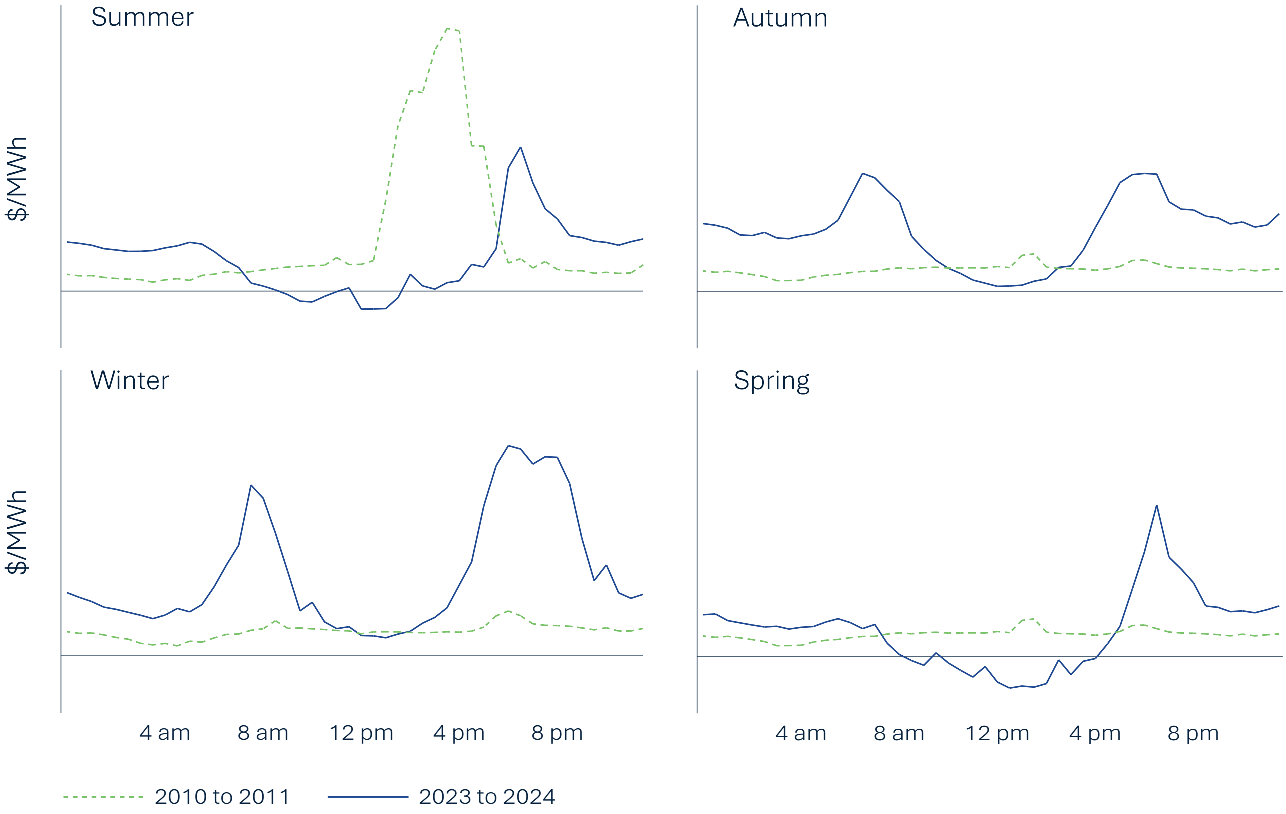
Price variability is a feature, not a flaw, of an energy-only spot market. Price variability allocates resources more efficiently when they are needed[13] and benefits a market that is designed for it. However, the nature of price formation will change, becoming more predictably variable on a day-to-day and seasonal basis,[14] and more unpredictably volatile as a result of unplanned withdrawal of capacity during generator and network outages, or extended and unforeseen periods of low wind and solar output ('dunkelflauten').

Intraday price variability has increased as abundant solar generation lowers prices during the day, while higher-priced generation satisfies evening demand peaks. This price spread provides the economic basis for energy storage: charging amid low prices and discharging when prices are higher.[15]

Seasonal pricing has also changed. Figure 22 depicts spot market pricing outcomes in South Australia, where coal power stations have been retired and there is significant VRE penetration. Fifteen years ago, pricing was relatively smooth across the day, with higher prices driven by air-conditioner use in the summer afternoon.[16] Since then, intraday and seasonal price spreads have increased markedly, with prices at their highest during winter evenings. VRE generation is scarcer in winter, when gas prices tend to be higher due to the use of gas for space heating.[17]

[13] Submissions to the initial NEM Review consultation from AGL Energy, Snowy Hydro, ENGIE and ACEN Australia.
[14] For example, solar PV is predictable in the sense that it follows the predictability of the sun (i.e. more electricity in the middle of the day and in the summer months when sunlight hours are greater).
[15] AER (2024), Wholesale electricity market performance report 2024, p 90.
[16] Strengers (2011), 'Air-conditioning Australian households: The impact of dynamic peak pricing', *Energy Policy*, volume 38, issue 11.
[17] AER (2024), State of the energy market 2024, p 152.

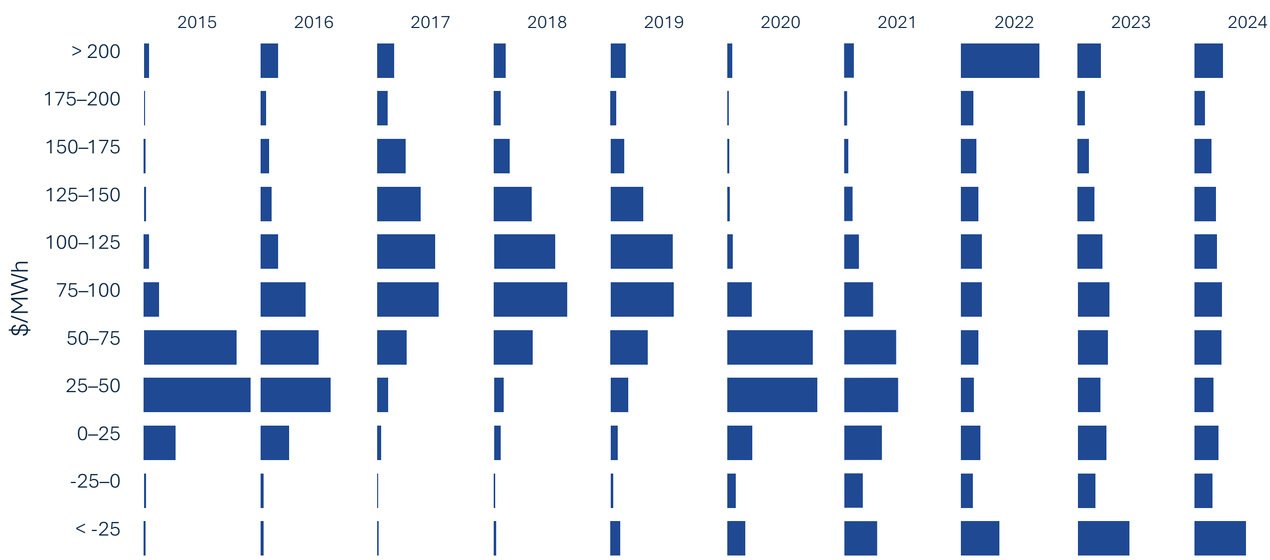
Figure 22 – Average seasonal and time-of-day 30-minute spot prices (2023 dollars) in South Australia, 2010 to 2011 and 2023 to 2024



Sources: AEMO MMS data, ABS CPI data, NEM Review analysis.

Figure 23 (below) shows the distribution of spot prices over the past decade in South Australia. As the South Australian market has become more reliant on VRE, periods of negative spot prices and higher peak prices, once rare, have become a feature of the price cycle.

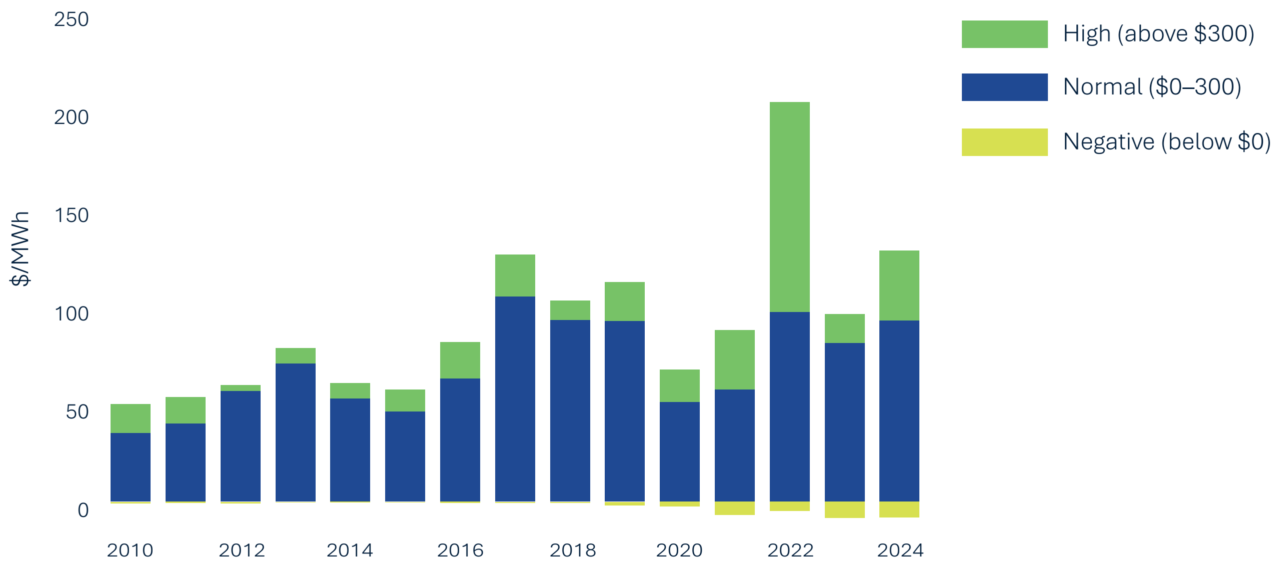
Figure 23 – Distribution of 30-minute spot prices (2023 dollars) in South Australia, 2015 to 2024



Sources: AEMO MMS data, ABS CPI data, NEM Review analysis.

Across the NEM, average real spot prices and price variability have increased over the past 15 years. Figure 24 (below) shows high and negative prices playing a growing role in overall annual prices.

Figure 24 – Contribution of high, normal and negative prices to the annual NEM price (2023 dollars) weighted by native demand, 2010 to 2024



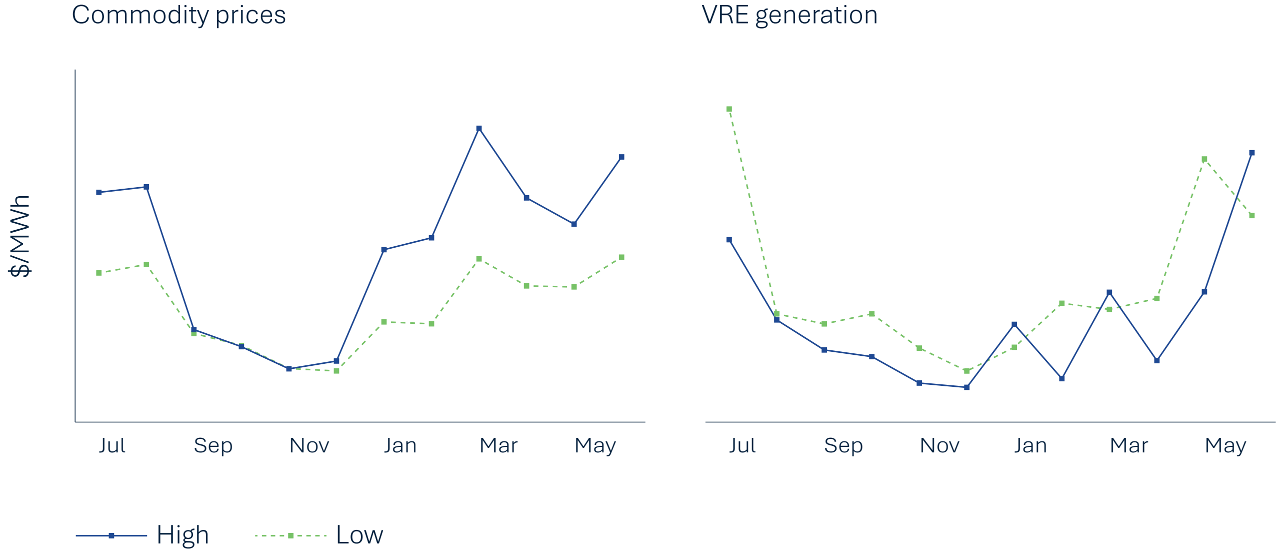
Sources: AEMO MMS data, ABS CPI data, NEM Review analysis.

Since the 1990s, overall prices have risen as the NEM progressively absorbed an oversupply of legacy coal-fired, fully depreciated plant. Prices shifted to reflect the need for long-run investment rather than just recovery of short-run costs.

Weather and fuel costs increasingly drive price volatility. Modelling undertaken by Aurora Energy Research for the NEM Review considered the impacts of different gas prices and weather conditions (with renewable output derived from high and low-resource years from the past decade) on the spot market to 2040. The results are intuitively obvious: windy conditions with low gas prices produce very low prices. Wind droughts and higher gas prices produce much higher electricity prices.

The potential variation is shown in Figure 25, which depicts modelled prices in 2039–40 under different gas price scenarios and under different weather scenarios that affect VRE generation.

Figure 25 – Forecast New South Wales time-weighted-average 30-minute spot price distribution (2023 dollars) in 2039–40 in different commodity and weather scenarios



Source: Aurora Energy Services modelling for the NEM Review.

2.2 Operational prices are becoming less certain

AEMO's pre-dispatch process generates prices from five minutes to five days ahead of dispatch. These price forecasts are not predictions but are simply the result of market participants' current intentions to offer their supply based on AEMO's forecast future demand. As conditions change, participants can alter the quantities of supply in the price bid bands they set. This 'rebidding' allows the market to clear in real time. However, with more weather-driven generation and variable demand, it is becoming more difficult to anticipate market conditions the further into the future one observes.

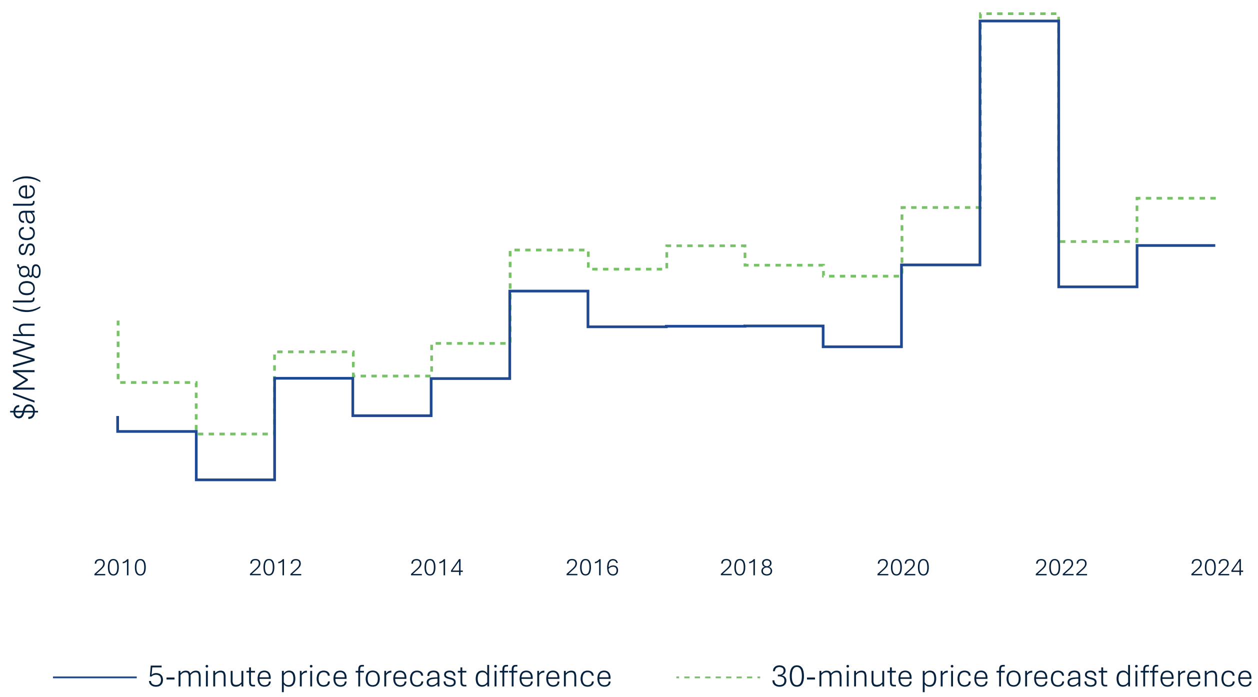
The average difference between the actual price and the pre-dispatch price[18] across the NEM in 2010 was about $7/MWh 5 minutes from real-time, and about $17/MWh 30 minutes ahead of real time (2023 dollars).[19] The corresponding differences in 2024 were about $35/MWh for 5 minutes and about $55/MWh for 30 minutes.

Several factors may explain why these differences are becoming more acute:

- Reliance on weather-dependent VRE generation, which is inherently difficult (but not impossible) to forecast.
- Growth in consumer energy resources (CER) such as solar PV and batteries, which are not visible to AEMO in the same way that other generators are.
- Increased utility battery bidding and the use of auto-bidding software, which research has associated with higher pre-dispatch price differences.[20]

18 Mean absolute error is used to indicate 'average difference' for this purpose.
19 Source: AEMO MMS data, ABS CPI data, NEM Review analysis.
20 Prakash et al. (2025), 'The scheduling role of future pricing information in electricity markets with rising deployments of energy storage: An Australian National Electricity Market case study', Energy Economics, vol. 142.

Figure 26 – Annual NEM-wide mean absolute differences of pre-dispatch and actual price outcomes (2023 dollars), 2010 to 2024



Sources: AEMO MMS data, ABS CPI data, NEM Review analysis.

2.3 Gas will continue to influence prices at certain times of the day and year

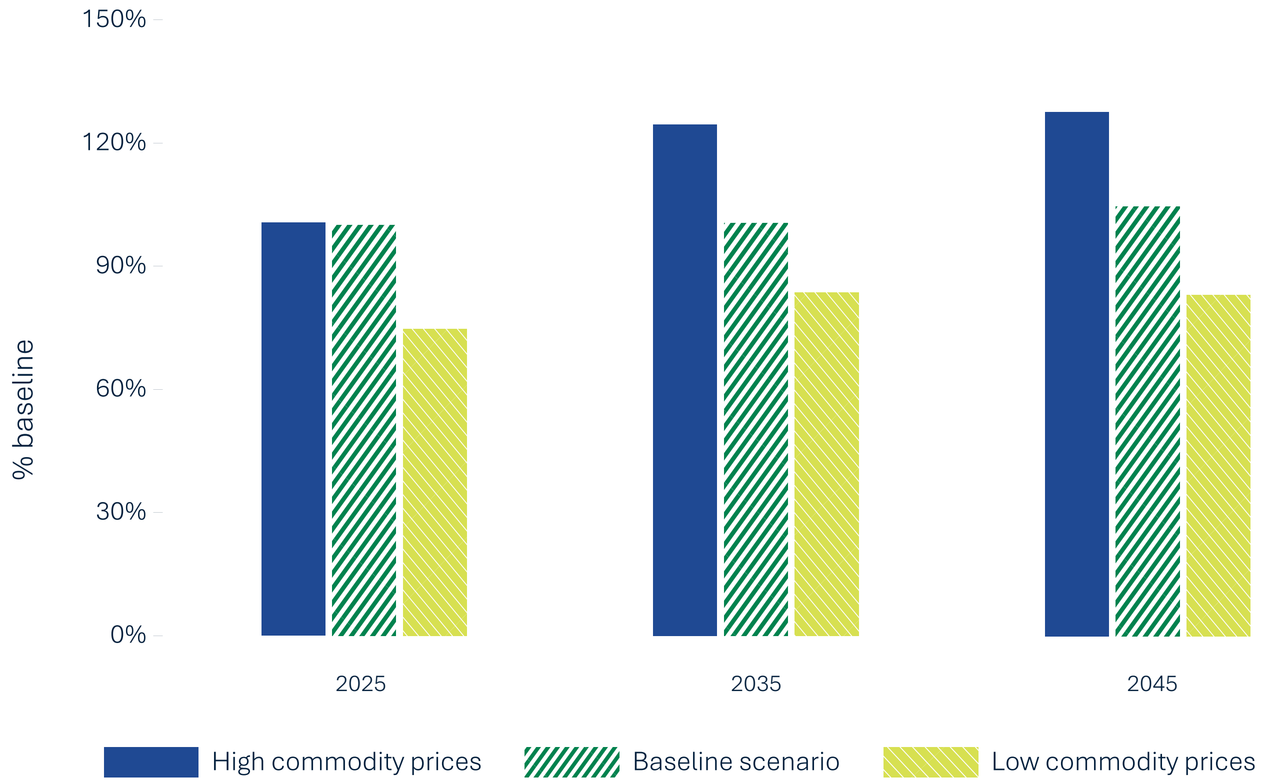
Gas prices remain highly correlated with electricity prices.[21] Global gas prices reflect the opportunity cost of the NEM's gas-fired generators. These generators will only generate if the value of their electricity exceeds the equivalent value they would receive from selling their gas to the gas market. Gas prices therefore influence electricity prices particularly acutely outside solar hours and during VRE droughts.[22] Stakeholders have noted that the price of gas generation is often used as a benchmark for bids by batteries, hydro and pumped hydro, whose short-run marginal costs are the opportunity costs of dispatching at other times.[23]

In this way, international gas prices sometimes set NEM spot prices even when another form of flexible generation is the nominal price-setter. For example, gas-fired generators contributed only 12% of dispatched energy from 2014 to 2021 but were estimated to have influenced the price of almost 75% of generation.[24] Gas generators are likely to continue to do this during times of scarce VRE supply. AEMO expects the NEM to rely on gas as a strategic reserve, particularly during VRE droughts and extreme weather events.[25] The chart in Figure 21 which depicts the changing nature of marginal costs shows that gas is projected to continue to play a role as firming generation during the transition.

[21] Nolan et al. (2022), 'The role of gas price in wholesale electricity price outcomes in the Australian National Electricity Market', Centre for Applied Energy Economics and Policy Research working paper.
[22] AEMO (2025), Submission to the initial NEM review consultation, p 14.
[23] Submissions to the initial NEM Review consultation from AEMO and the Energy Efficiency Council.
[24] Hirschhorn et al. (2022), Is electricity pricing running out of gas?, Boston Consulting Group article.
[25] AEMO (2024), 2024 Integrated System Plan for the National Electricity Market, p 69.

Aurora Energy Research modelling suggests international gas markets may continue to have an ongoing influence on spot prices. Figure 27 compares Aurora's baseline forecasts, in which the long-term average gas price is assumed to be $14.8/GJ, with alternative scenarios in which gas prices are significantly lower ($10/GJ) and higher ($20/GJ). The effect on NEM spot prices is observable: for example, the modelling suggests electricity prices in the higher gas price scenario would be around 20% more in 2045 than they would be in the baseline gas price scenario. The evolution of the role of CER, storage and demand response (DR) as participants in the wholesale market could impact these outcomes.

Figure 27 – Forecast time-weighted-average New South Wales real prices (relative to the baseline in 2025) under three commodity price scenarios, 2025 to 2045



Source: Aurora Energy research for the NEM Review.

2.4 Hidden resources are impeding price formation

More resources are increasingly invisible to the market, including consumer energy resources (CER) and DR providers. These 'hidden resources' respond to price but do not participate in price formation. If this trend continues, it is likely to undermine efficient price formation and lead to over-investment in grid-scale resources.

DER – including rooftop solar, household batteries and electric vehicles (EVs) – are transforming the NEM. Conservatively, it is estimated that consumers may spend between $100–150 billion on CER in the next 25 years, excluding EVs.[26] These resources are not fully visible to AEMO or other market

[26] A conservative estimate of total spending on small-scale battery (embedded and aggregated) and solar uptake (rooftop and PV) alone, based on AEMO's 2024 ISP step change scenario and prices as per the 2024–25 CSIRO GenCost report's current policies pricing. See AEMO (2024), 2024 Integrated System Plan – Step Change Scenario, and CSIRO (2024), GenCost 2024–25: Current Policies Pricing.

participants as they do not offer their generation into the market via the same systems and software used by larger resources (such as grid-scale batteries and generators). Their invisibility affects the dispatch process, complicating forecasting and undermining efficient price formation, at an extra cost to consumers. Put simply, if AEMO is not aware that resources will respond to price (because they have not informed AEMO via the bidding process), it will schedule other resources that will respond simultaneously. This will then lead to system imbalance which will require even more resources to be deployed to correct it. Unless price-responsive resources are coordinated through the market pricing mechanism, batteries could be charging while other batteries are discharging – leading to significant over-investment and wasted societal resources.

AEMO's ISP assumes that within four years most small batteries and EVs will be well-coordinated or 'orchestrated'. However, it remains unclear whether this will occur. Consumer uptake of orchestration services remains low, estimated at about 14%.[27] AEMO estimates about $4.1 billion of extra grid-scale investment will be needed if the proportion of orchestration of consumer batteries does not grow.[28] Furthermore, the benefits will be undermined to the extent the level of orchestration grows but remains invisible to the dispatch process. Consumers would pay for this over-spending – the result of building unnecessary generation and procuring of frequency control ancillary services (FCAS) to correct frequency deviations caused by unanticipated responses by hidden DER – which could be avoided through greater visibility or participation in dispatch.

Distributed solar and distributed storage

Distributed solar: Rooftop solar has become the fuel source with the highest registered capacity in the NEM.[29] In the past five years consumers have installed distributed solar at about twice the rate of utility-scale solar. AEMO projects the overall capacity of distributed solar to double in the next decade, from more than 25 GW to 50 GW.[30] While rooftop solar has relatively predictable output, its integration into the market remains challenging because it does not participate directly in the dispatch process.

Distributed storage: Sales of distributed storage, such as home batteries and vehicle-to-grid EVs, are increasing. AEMO expects adoption to continue to grow strongly into the early 2030s, projecting capacity to increase from 1 GW to 7 GW in 2029–30, then to 34 GW in 2049–50.[31] This growth is more challenging than solar because it is difficult to forecast how batteries will be used. Batteries can be optimised for energy arbitrage, ESS, demand shifting or self-consumption. They can also join aggregated VPPs. However, VPPs are typically not visible to AEMO or the wider market.

DR involves consumers adjusting their electricity use in response to price signals or grid conditions. Changing wholesale market dynamics will increase the value and importance of DR in both reducing peak demand and potentially supporting minimum system load.

However, the integration of DR into the spot market, particularly through the wholesale demand response mechanism, has faced challenges. Only a few demand response service providers have

27 Graham & Mediwaththe (2024), Small-scale solar PV and battery projections 2024 Commissioned for AEMO's draft 2025 Input, Assumptions and Scenarios Report, p 36.
28 AEMO (2024), 2024 Integrated System Plan for the National Electricity Market, p 67.
29 Ibid.
30 AER (2024), State of the energy market 2024, p 293.
31 AEMO (2024), 2024 ISP data (step change scenario).

registered, and the total participative load has been relatively low. Financial and regulatory incentives may be insufficient to encourage wider participation. If these barriers remain unaddressed, potential DR resources will remain invisible to AEMO and other market participants, and the potential benefits for grid stability and cost reduction will be unrealised.[32]

Role of demand response in price formation

Intraday and annual dynamics: As generation becomes more weather-dependent and variable, demand flexibility can play a greater role in smoothing out intraday demand troughs and peaks. In the longer term, annual price variability will increase as weather outcomes drive wholesale market dynamics. DR's ability to support reliability will be of high value in low VRE weather years.

Seasonal shifts: Most market analysts expect seasonal demand peaks to shift from summer to winter in all states except Queensland, creating opportunities for seasonal demand flexibility. This shift may be prominent in cooler regions, which have higher costs in winter when energy use is high (due to spatial heaters) and wind and solar generation are low, requiring the dispatch of dispatchable generation to meet demand.

2.5 ESS-related interventions are increasing

ESS helps keep the electricity system within its technical operating envelope, during normal operation and following contingencies, so that it can securely deliver electricity. Traditionally, power stations such as those powered by coal, gas or hydro provided ESS such as system strength and inertia as a by-product of their operation. These generators use large spinning machines that help stabilise the grid by resisting sudden changes in frequency and supporting voltage levels. In contrast, VRE sources like wind and solar connect to the grid through power electronics called inverters. Standard inverters do not inherently provide the same stabilising effects as traditional generators. However, with advanced designs – such as in grid-forming inverters or advanced battery systems – these technologies can be engineered to deliver some system services and support grid stability.

The NEM requires ESS to maintain a stable and secure power system. Without these services, the grid can face outages, equipment damage, market disruptions and broader economic impacts. When there are insufficient alternative sources for these services, AEMO must dispatch older thermal plants through out-of-merit-order directions. This can lead to the use of more expensive or less efficient energy,[33] highlighting the financial and environmental costs of the lack of ESS from newer, more sustainable sources.

[32] AEMC (2025), Review of the Wholesale Demand Response Mechanism.
[33] AER (2024), State of the energy market 2024.

Increasing number of out-of-merit-order directions

AEMO directs market participants to ensure power system security, typically when the market fails to deliver enough system strength, inertia or voltage support through normal dispatch. These directions are currently most common in South Australia due to its high penetration of inverter-based resources and limited local synchronous generation.

Intended as a last resort to protect system security, these directions often involve keeping synchronous generators like gas or diesel plants online, or starting them, even when not economically optimal. This ensures stability but it is inefficient and undesirable in the long term.

In recent years, the number of these directions has been higher than expected for a last-resort mechanism. The costs associated with these directions can be high, ultimately borne by consumers, contributing to a growing proportion of the wholesale component of consumer bills.[34] Since these costs are determined outside the market, they do not reflect the market-determined value of the service and include a premium for involuntary participation. They also cannot be hedged or proactively managed by end users. Increased reliance on the use of directions is likely to have a growing impact on energy costs for consumers.

The transition to renewable generation coincides with a transformation of the nature of electricity demand. AEMO forecasts that electricity consumption will almost double by 2050,[35] driven by electrification, economic growth, industry changes and other factors. The interaction between dispatched generation and consumers will also become more complex: consumers, enabled by smart meters, smart appliances and CER, will be able to be more self-reliant and better able to respond to price signals by shifting their consumption.

[34] AER (2024), Wholesale electricity market performance report 2024, p 138.
[35] AEMO (2024), 2024 Integrated System Plan for the National Electricity Market, p 22.

Implications for the derivatives market

Wholesale spot prices are likely to become more predictably variable and unpredictably volatile due to the growing dependency on weather. This variability and volatility can bring economic benefits but also increases the level of risk that market participants must manage. This risk will exist irrespective of the market's design, shifting from an energy-only to an energy-plus-capacity market would not alter the nature of physical risks in a weather-dependent system (alternatives to energy-only market designs are addressed further in **Chapter 3: Ensuring effective operation of the spot market**).

Liquid and well-functioning derivatives markets are essential for managing this risk, maintaining competition and supporting the NEM's open-market approach.[36] These markets allow participants to transfer risk to those best able to manage it, enabling retailers to offer predictable prices to consumers and helping generators secure revenue certainty.

The transition to renewable energy presents specific challenges for derivatives markets, including weather-driven volatility, declining liquidity, and rising access and cost barriers (Figure 28).

Figure 28 – Key challenges in the derivatives market

Weather-driven volatility

Increasing weather-driven spot market variability creates challenges, particularly for participants lacking the scale or balance sheet to manage sharp price fluctuations. This affects contract market competition, liquidity and access to exchange-traded contracts.

Liquidity concerns

Derivatives are increasingly important for managing risk in a weather-dependent system. However, liquidity has declined in South Australia in particular. VRE saturation may reduce the source of current hedging products, necessitating innovation.

Access and cost barriers

Smaller retailers may struggle to access exchange-traded contracts and face premiums to take part in exchange and over-the-counter (OTC) markets. Limited working capital for exchange margining requirements can prevent participation, forcing reliance on more expensive, less transparent OTC markets.

Credit risk

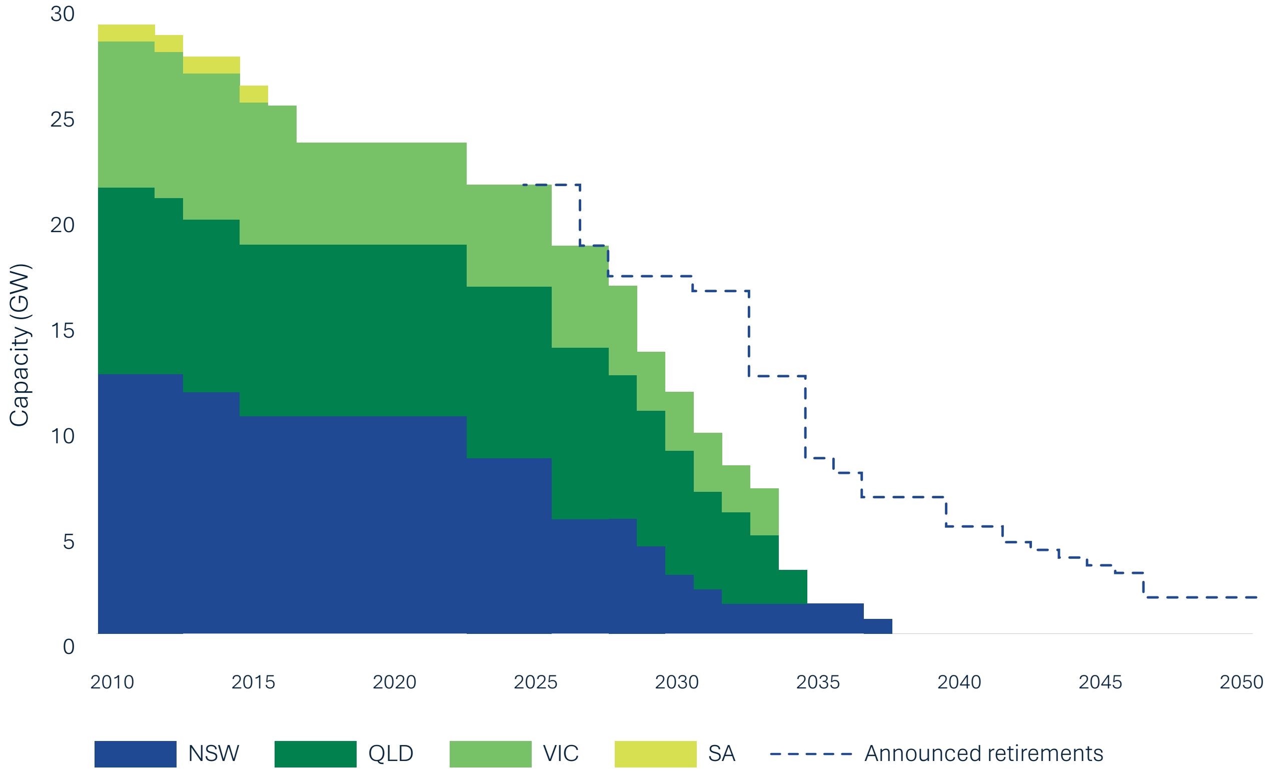
Credit risk can limit the pool of willing counterparties for OTC contracts and may result in premiums, affecting their ability to manage spot price risk efficiently.

[36] Submissions to the initial NEM Review consultation from Origin Energy, ACEN Australia, Clean Energy Council and CleanCo Queensland.

2.6 The derivatives market needs to evolve to continue to support price transparency and liquidity

The energy transition will change the way market participants manage forward risks, with thermal generators scheduled to retire in coming decades (Figure 29).

Figure 29 – Projected coal power station closures, 2009–10 to 2049–50



Sources: AEMO 2024 ISP data (step change scenario); announced retirements are from AEMO's Generating Unit Expected Closure Year October 2025. Note: The 2024 ISP projections were modelled before the NSW Government extended Eraring Power Station's operation and the publication of the Queensland Energy Roadmap.

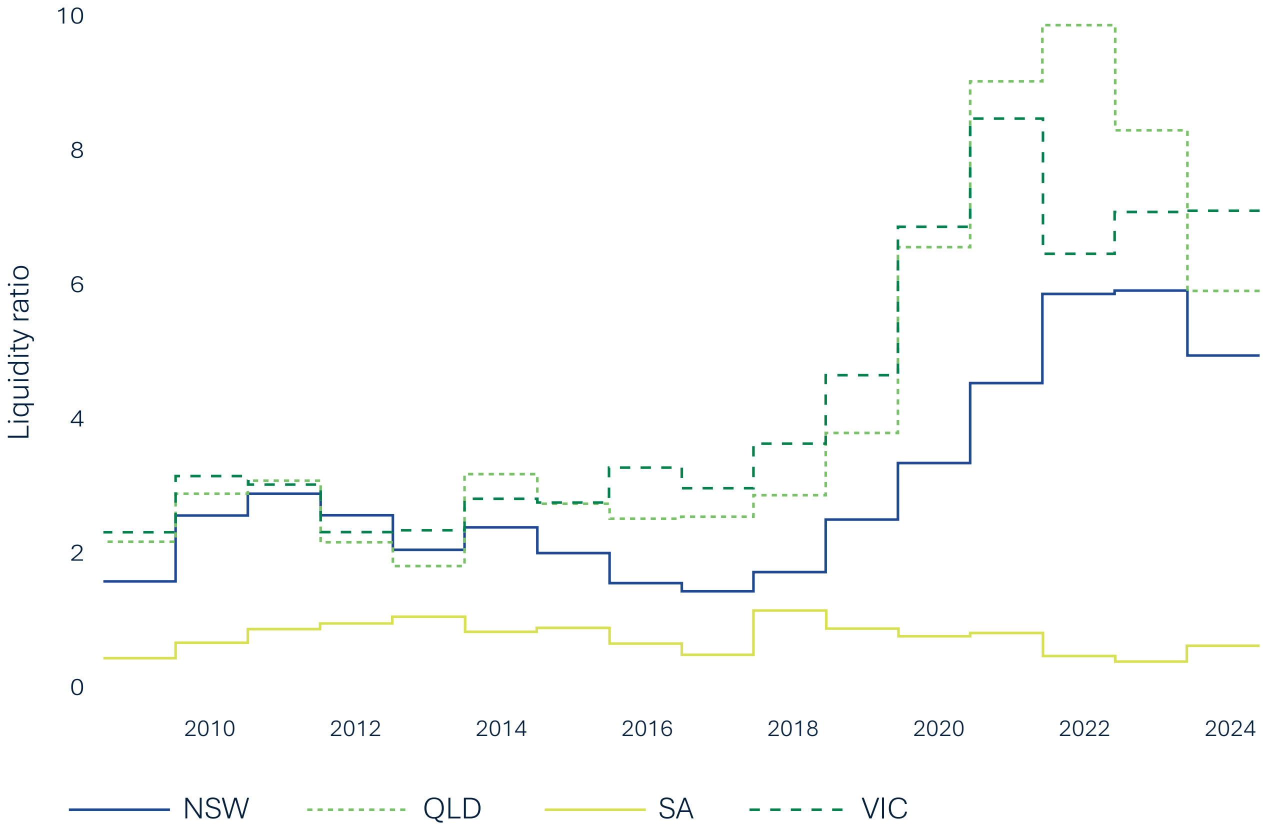
Standard exchange-traded contracts developed in the 2000s allowed market participants to hedge forward risks. Supply-side participants at that time included thermal and hydro generators, while demand-side participants included retailers and commercial and industrial (C&I) users with relatively stable, predictable electricity loads. Going forward, VRE generation like solar and wind (bulk energy) is expected to meet rising demand for bulk electricity. However, the available supply from these plants depends on weather patterns. This means a VRE generator's ability to physically commit to supply electricity during a given period is influenced by the accuracy of weather forecasts. This contrasts with a coal, gas or hydro plant, which assesses whether it has access to coal, gas or water. As a result, VRE is less well placed to defend existing derivative contracts, such as baseload swaps or caps.

The products developed to hedge risks at the time the NEM commenced were designed for coal, gas and hydro generators as well as retailers and C&I users. As thermal units retire, liquidity and price transparency will be at risk unless derivatives markets evolve to allow energy to be traded from new technologies: providers of bulk energy, shaping and firming services. It is critical that derivatives markets evolve in a timely manner so new forms of contracts suitable for new technologies are available before coal plants retire.

The volume of energy traded on the ASX has increased considerably over the past five years. Swaptions, which, for a premium, can reduce buyers' exposure to price volatility, have overtaken baseload swaps to become the most widely traded energy products on the ASX.

The exception is South Australia, where liquidity is declining and has been low for many years (Figure 30). Trade volumes in the state's derivatives market have consistently been lower than in other NEM regions. The South Australian market is highly dependent on VRE bulk energy and peaking plants, and as a result has prolonged periods of negative prices and higher peak prices when VRE is scarce. Contract volumes and sizes (energy per trade) have fallen and, unlike other NEM markets, caps, used to hedge against price spikes, make up most of the state's ASX energy trade,[37] which is dominated by a few large market participants.[38] The dynamics of South Australia's derivatives market provides potential insights into the challenges other state markets face as east-coast coal plants retire in the future.

Figure 30 – Volume of ASX-traded electricity contracts relative to native demand, 2010–24



Source: ASX Energy data, NEM Review analysis. The liquidity ratio, a measure used by the AER, is the volume of all ASX-traded contracts divided by total native demand.

[37] AER (2024), Wholesale electricity market performance report 2024, p 129.
[38] Op. cit. p. 134.

Other factors limiting liquidity in South Australia include limited competition for long-duration dispatchable electricity generation. While the Panel notes that vertical integration may be a legitimate commercial response to managing risk, it cannot occur at the expense of transparent and liquid forward markets that provide end-users with confidence in their pricing outcomes.

2.7 Suitable contracts need to be available before coal plant exits

As new weather-dependent technologies become the primary source of bulk energy (i.e. wind and solar) it will be important for derivatives markets to evolve beyond the products designed for the electricity system of the late 20th century (i.e. baseload swaps and caps). Stakeholders have demonstrated to the Panel that innovation is occurring; time-of-day and fixed shape products are being developed and traded.

However, while derivatives markets are adjusting to changes in the NEM, the pace of change has been too slow. Work is needed to bring innovative contracts to market more quickly. The transition to weather-dependent VRE, shaping and firming, alongside the retirement of coal generation, is changing the nature of spot price risk. Market participants see a need for new contract types, such as time-of-day blocks, morning and evening peak caps, and battery tolling agreements. OTC markets are innovating, and morning and evening peak swaps were listed on the ASX from July 2025. But exchange contract innovation is slow and some stakeholders question whether innovation will be quick enough to meet evolving market needs. Regulatory and market dynamics also influence innovation in the derivatives market. The development of new contracts involves multiple steps, including market surveys, risk assessments and regulatory approvals, while factors such as business priorities influence the timing and success of new products.

Implications for long-term investment

As NEM requirements and technologies evolve, potential investors in new generation and storage assets face novel and increasing risks. Concurrently, the markets for financial instruments in regions with high penetrations of VRE are becoming increasingly thin. Historically, governments have supported investment through various interventions, as detailed in **Chapter 1: Introduction to the NEM.**

The Panel has identified that most historic policy interventions have been incomplete. For example, the Renewable Energy Target required investments in new renewables to displace the bulk energy from existing emissions-intensive generation. However, a more comprehensive policy suite would have also addressed critical services that these emissions-intensive generators provided, which are now absent unless supplied by other entities. These services include:

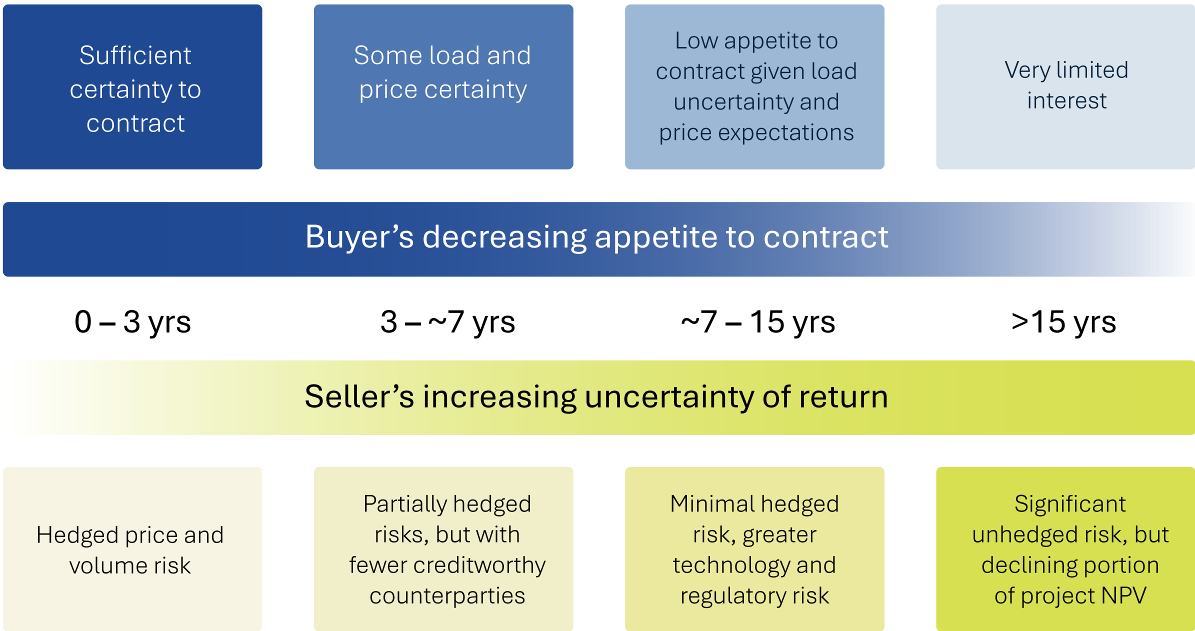
- **Shaping**: Matching the intraday and inter-day profiles of supply and demand to meet regular peaks
- **Firming:** Very long-duration and dispatchable resources that can be delivered as needed
- **Essential system services:** Ancillary services such as those services that maintain voltage, wave form and tolerance to faults
- **Usable hedging contracts:** Derivatives that allow market customers to manage risk and stabilise prices.

2.8 The tenor gap will persist

The Panel has identified the tenor gap as a reason the wholesale spot market and associated derivatives market are not driving efficient investment in the NEM (Figure 31). Derivative markets are typically short-dated, with exchange-traded contracts generally traded three years out. However, many new projects require contracts of 15 years or longer to attract financing given the inherent systemic risks associated with future demand uncertainty and technological change. This timing mismatch is compounded by the range of overlapping risks – technological, regulatory, credit and demand related – that suppress the availability and affordability of long-term offtakes. The result is the tenor gap: a disconnect between the long-lived nature of generation and storage assets, and the short-term signals the market currently provides.[39]

[39] Submissions to the initial NEM Review consultation from ACEN Australia (p 2) and ATCO Australia (p 1).

Figure 31 – The tenor gap



The NEM Review Panel conducted a targeted survey of market participants to further investigate the tenor gap. While specific information from this survey is commercially sensitive, it confirmed that retailers continue to largely contract only a few years in advance. It also highlighted that the size of the tenor gap is technology-specific, with notably larger gaps for peaking gas generation and pumped hydro, and notably smaller gaps for batteries and solar PV. Most retailers and other natural contract buyers (e.g. large commercial loads) can contract for 15 years or longer in the right circumstances, but in practice do so very rarely.

2.9 Coal exit uncertainties and entry before exit will need to be managed

Bringing new generation assets online before ageing coal plants exit may create a period of oversupply. This is necessary to avoid the risks of undersupply, including load shedding or blackouts. However, prolonged oversupply can drive prices down, deterring private investors from committing to new projects.[40]

The uncertainty over when large, ageing coal generators might exit the market makes investment decisions difficult. As very large and 'lumpy' sources of generation, coal generator exits are material to new investment revenue expectations.

Governments are managing coal exits through policies like state-based structured transition agreements and the Orderly Exit Management Framework. Notwithstanding these policies, stakeholders continue to raise concerns about coal exit uncertainties in the medium to long term.[41]

[40] Submissions to the initial NEM Review consultation from Iberdrola Australia (p 2) and Clean Energy Investor Group (p 4).
[41] Submissions to the initial NEM Review consultation from AEMO (p 4), Squadron (p 2), AEMC (p ii), Tesla (p 7), AFMA (p 2), Institute for Energy Economics and Financial Analysis (p 2), Clean Energy Council (p 6), Nexa Advisory (p 1), and Queensland Conservation Council (p. 3).

Investment challenges in other energy markets

Australia is not alone in facing challenges to incentivise new investment in energy services. Other markets are also struggling to attract investment. In seeking to address the NEM's investment challenges, the Panel has examined how other countries have tackled similar issues on their path to net zero.

Through its international consultation, the Panel has observed evidence of the shift to 'hybrid' markets. For example, London Economics presented evidence that electricity systems in North America are transitioning to electricity markets that are more regulated and have more government intervention. European energy experts at the International Energy Agency's 2025 Power Market Design Expert Workshop similarly emphasised the need for hybrid markets that allow long-term contracting to facilitate investment.

The Panel has considered a range of international mechanisms. These include:

Contracts-for-difference: Used in Britain to provide revenue certainty to new generators.

Centrally administered capacity markets: In the United States (e.g. New York and PJM Interconnection regional transmission organisation), these markets offer forward revenue streams to support system adequacy.

Reliability-based capacity mechanism: Ireland's mechanism provides indirect risk protection for retailers.

Market-driven approach: New Zealand's approach, centred on energy-only pricing and supported by scarcity pricing and demand response, highlights the trade-offs between market reliance and revenue certainty.

International experience highlights a range of mechanisms to support investment in energy systems, each tailored to local context, policy objectives and market design, with mixed success.

When assessed against the unique institutional and market characteristics of the NEM, it became clear that tailored solutions building on international ideas will be needed to meet the NEM's future investment needs.

Implications for consumers

In considering the trends and challenges facing the NEM, the Panel focused on how these will impact on consumers. Ultimately, the market only exists to serve consumers.

Consumers have diverse preferences in how they produce, use and manage their electricity. However, some outcomes are almost universally valued: reliable electricity at fair, stable and affordable prices. The Panel believes the market's success or failure must ultimately be judged by whether it delivers these outcomes.

The trends outlined in this chapter – the changing nature of generation in the spot market, liquidity pressures in derivatives markets and persistent challenges in providing the right signals for new investment – pose real risks to consumers. Without reform this trajectory would leave consumers materially worse off, with higher bills, reduced choice and declining confidence in the energy transition.

3

Ensuring effective operation of the spot market

Chapter summary

The energy-only spot market design has proven effective at dispatching resources in real-time and will continue to do so through the energy transition. The market provides sharp price signals that accurately reflect the balance of supply and demand in real-time and over operational time frames. It is a powerful mechanism for ensuring efficient resource utilisation and addressing near-term reliability issues as they arise.

The Panel acknowledges the operation of the spot market is not always perfect, with inefficiencies that can impede the most efficient outcomes. On balance, the Panel considers that these 'wrinkles' are manageable within the current market design. Many of the more material challenges to the operation of the spot market are best addressed through incremental reforms to the spot market and complementary reforms on the investment side of the market, rather than an overhaul of the spot market design. The costs, risks and complexity of adopting alternatives are likely to outweigh the potential benefits (**Recommendation 1**).

Through the energy transition, the drivers of price formation in the energy-only market are fundamentally changing. Historically, the marginal price of electricity was strongly linked to generator fuel costs. In the future, price formation is likely to be driven by very low short-run marginal cost renewable energy, the opportunity cost of energy-constrained resources such as batteries, hydro power and pumped hydro, price sensitivities of responsive distributed energy resources (DER) and consumer energy resources (CER), demand flexibility and gas prices.

To maintain an energy-only market that is fit for the future, the Panel recommends the following reforms:

- By 2030, require certain price-responsive resources to be visible or participate in dispatch (**Recommendation 2**).
- Unlock the full benefits of more consumers becoming price-responsive (**Recommendation 3**).
- Address emerging issues, including around bidding practices, visibility of battery state of charge information, and the impact of transmission network outages on the spot market (**Recommendation 4**).
- Ensure market price settings adapt to the changing needs for energy services, technologies and market dynamics (**Recommendation 5**).

Recommendations

1 Maintain the real-time regional energy-only spot market as the core market for efficient dispatch and rewarding the provision of physical energy services

A. Retain the real-time regional energy-only spot market with necessary rule changes to ensure its continued efficient and competitive operation, recognising that increasing spot market variability and volatility can be managed.

B. Do not create additional mandatory centralised short-term (operational timeframe) markets, such as capacity markets or physical ahead markets.

C. Do not implement locational marginal pricing or variants considered previously.

D. Do not create distribution-level wholesale energy markets. Instead, facilitate distribution-level energy resources to participate in regional markets and use dynamic operating envelopes and dynamic network tariffs to manage local constraints.

2 Energy ministers should require that a wider range of price-responsive resources (PRR) are visible or participate in dispatch so they can contribute effectively to market price formation

A. Energy ministers should implement a mandatory framework for PRR visibility and participation in dispatch. Ministers should give effect to this by:

(i) Tasking the Australian Energy Market Operator (AEMO), in consultation with industry and consumer representatives, to develop by December 2026 a framework that defines fit-for-purpose visibility modes and their adoption into operational forecasting; establishes thresholds for mandatory participation; and provides advice on consumer benefits and implementation pathways.

(ii) Progressing amendments to the National Electricity Law (NEL) and National Electricity Rules (NER) to enable full implementation of the framework by 2030.

The Panel recommends the framework should apply the following parameters and initial thresholds (within Integrating Price-Responsive Resources zones[42]):

- Portfolio aggregations of small-scale storage (without co-located load) that in aggregate exceed the NER's bidirectional unit (BDU) registration threshold (>5 MW) should be required to participate in dispatch mode (active) or as a BDU.
- Consumer energy resources (CER) portfolio aggregations with remote automated control and an aggregated capacity exceeding the NER's scheduled generation registration threshold (>30 MW), should be required to participate in dispatch mode (inactive), with dispatch mode (active) remaining voluntary. Aggregations below this threshold should provide quarterly reporting to AEMO identifying loads subject to such arrangements.

[42] Geographic zones defined by AEMO in the Voluntary Scheduled Resources Guidelines (released 27 November 2025). Review of zones will be considered in AEMO's review of VSR Guidelines that must occur by 1 May 2030.

- Large industrial and commercial loads with aggregated capacity of price-responsive load across their portfolio that exceeds the NER's scheduled generation registration threshold (>30 MW), including those operating under price-contingent demand response contracts, should be required to provide load-intention data to AEMO via a dedicated visibility-only difference-bid mode or, alternatively, participate through the wholesale demand response mechanism (WDRM).
- Retailers offering pool-price pass-through arrangements or price-contingent demand response contracts, where the aggregated capacity of price-responsive load is below the scheduled generation registration threshold (<30 MW), should be required to submit quarterly reports to AEMO identifying all loads subject to these contractual arrangements.

B. Energy ministers should establish a structured support framework to encourage currently non-scheduled PRR to participate in dispatch mode (active), the WDRM, or as scheduled loads, generators or bidirectional units.

3 Governments should focus reforms and support for CER on facilitating market participation to enable consumers to benefit from being price-responsive

A. Energy ministers should focus the National CER Roadmap on – and ensure sufficient resources are allocated to – delivering the critical roadmap elements that enable market participation (e.g. technical standards) and provide consumer protections.

B. Government incentives for investment in CER, such as for batteries, should support resources that are enabled to participate actively in the market through aggregators and are ready for dynamic network connections.

4 Market bodies should use the rule change process to ensure the efficient and competitive functioning of the real-time energy-only spot market

A. Market bodies and the Australian Competition and Consumer Commission (ACCC) should work together to develop a broader understanding of the risks and opportunities created by algorithmic bidding to inform regulatory responses, including rule changes if needed.

B. Market bodies should analyse whether publishing battery state of charge information from July 2025 adequately mitigates reliability risks or whether further reforms are needed.

C. Market bodies should work to minimise the impact of transmission network outages on the energy-only spot market.

5 The Reliability Panel should consider adjusting the form of the market price settings over time

The Reliability Panel should provide a long-term outlook on the form of the market price settings as an enduring and ongoing responsibility. It should undertake a review in 2026 which provides an initial long-term outlook on the form of the market price settings and the appropriateness of the form of the settings for the future electricity market.

Recommendation 1: Maintain the real-time regional energy-only spot market as the core market for efficient dispatch and rewarding the provision of physical energy services

3.1 The energy-only spot market is a core strength of the NEM, but the shape of supply and demand is changing

The NEM was designed as a mandatory gross pool with an energy-only market, to align with the Hilmer reforms' goals of competition and efficiency.[43] In this market, scheduled generators must offer their available capacity at prices currently ranging from the market price floor (MPF) of negative $1,000/MWh[44] to the market price cap (MPC) of $20,300/MWh.[45] Scheduled generators submit bids by 12:30pm the day prior to dispatch, specifying the price and volume they intend to offer across the trading day.[46] While price bands are fixed, generators can continue to update ('rebid') their offered volumes every 5 minutes until dispatch.[47]

The highest-priced offer needed to meet demand sets the spot price in real time (uniform-clearing price as opposed to pay-as-bid) every 5 minutes and in every region. All dispatched generators receive this single price at the regional reference node, reflecting a key feature of the NEM: the lack of price disaggregation across sub-regions or at the distributed level.

This energy-only, gross pool, real-time, regional pricing mechanism creates sharp, transparent price signals that seek to reflect supply-demand conditions. Price volatility is a fundamental feature of this market design, allowing prices to reflect the real-time supply-demand balance and the level of resource scarcity.[48] These price signals play a role in driving investment over the long term, with higher prices during times of generation scarcity signalling the need for new capacity. Derivative markets capture expectations of spot prices over the medium term. For the market to remain sustainable, it must also facilitate generators recovering efficient fixed and variable costs over the life of the asset. The NEM is designed to dispatch the cheapest generator bids first, followed by progressively more expensive offers, until enough electricity is produced to meet demand, subject to any network or technical constraints.[49] Traditionally, this merit order consisted of generation to suit baseload, mid-merit and peaking demand, each with progressively higher short-run marginal costs (SRMC).

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43 A gross pool market requires generators to sell all electricity through the market pool. This is in contrast to a net pool market where generators can enter into bilateral contracts directly with market customers for delivery of electricity before they sell any remaining electricity in the market pool.

44 AEMC (2023), National Electricity Amendment (Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap) Rule.

45 AEMC (2025), AEMC updates market price cap for 2025–26 media statement, 27 February.

46 AEMO (2025), 'Spot Market Operations Timetable', 31 July, p 5.

47 Ibid.

48 Submissions to the initial NEM Review consultation from CS Energy (p 2) the Superpower Institute (p 6).

49 AER (2024), State of the energy market 2024, p 17.

Why uniform clearing price rather than pay-as-bid in the spot market?

The NEM operates using a uniform clearing price. Under this system, all generators receive the same transparent clearing price, set by the marginal cost of the last generator dispatched to meet demand. This is designed to encourage all generators to bid their true costs. The market then selects the lowest-cost combination to supply electricity, with the aim of delivering efficient, least-cost outcomes for consumers under conditions of effective competition.[50]

By contrast, a pay-as-bid system forces participants to submit bids that reflect their best guess of what the price will be for the most expensive needed resource, instead of bidding their actual costs.[51] This encourages gaming and strategic bidding. The most sophisticated players tend to win, while smaller or newer participants are disadvantaged. Prices under pay-as-bid reflect bidding strategies, not actual system costs, which undermines transparency and weakens investment signals.

Uniform clearing prices also support liquid derivatives markets (a key means by which participants can manage risk), clear price signals for investment, and efficient dispatch – all critical as more renewables, storage and flexible demand are integrated into the grid.

However, the physical characteristics of the system are undergoing significant transformation. A generation fleet composed primarily of near-zero SRMC variable renewable energy, opportunity-cost-based generation such as batteries and hydropower (with limited energy available compared to capacity) and higher-cost firming (such as gas-powered generation) creates a very different supply curve.

Figure 32 – Schematic of the NEM's past (left) and future (right) supply curve

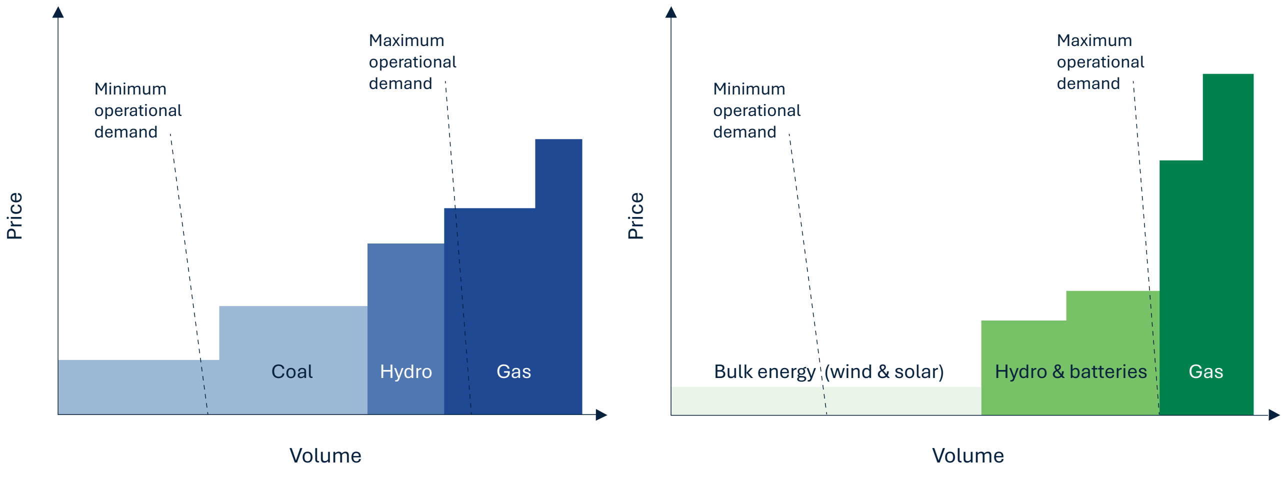


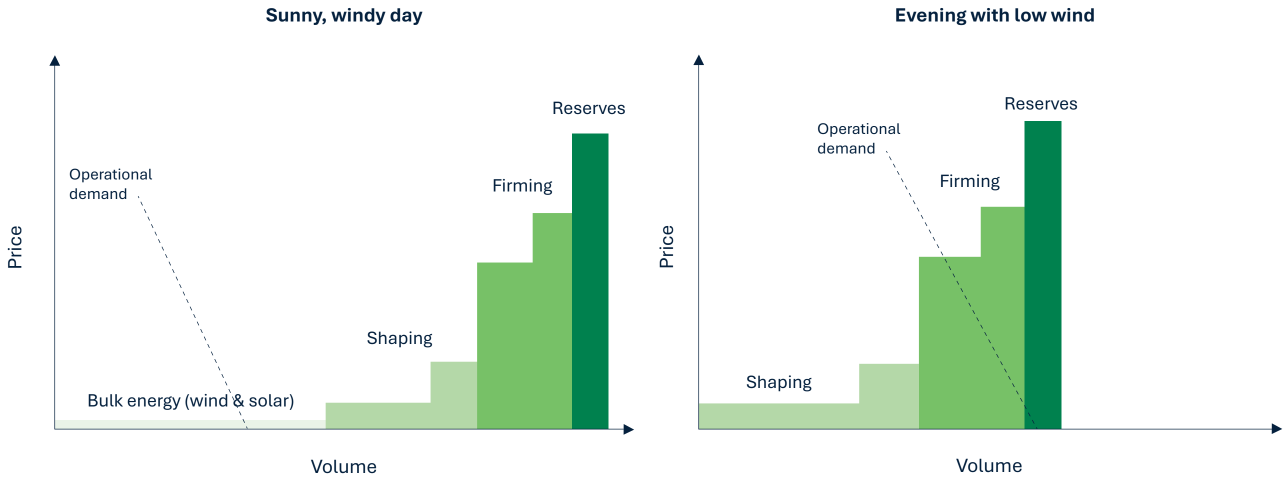
Figure 32 shows how the supply curve changes as more renewable generation enters the NEM. Renewables, with near-zero SRMC, sit at the bottom of the generator bid stack and displace higher-cost generators such as coal.

Figure 33 shows how the supply curve shifts with changing renewable output. When wind and solar energy are abundant, the supply curve flattens due to the availability of near-zero marginal-cost

50 Watkiss, J.et al. (2023), Time to Double Down on Uniform Pricing in U.S. Energy Markets, in Yale Journal on Regulation.
51 ISO New England (2006), The Benefits of Uniform Clearing-Price Auctions for Pricing Electricity, p 1.

supply. When renewable generation is scarce, the curve steepens and contracts, leading to higher and potentially more volatile prices.

Figure 33 – High (left) and low (right) weather output affects the supply and demand curve



The NEM was designed in an era where grid-based demand was relatively inelastic in the short term, meaning consumers were largely unable or unwilling to shift their electricity use in response to price changes. However, the growing integration of CER, DER and both small and large-scale demand flexibility (all partial grid-substitutes) is leading to more elasticity of demand for grid electricity.[52] The transition to greater variable renewable energy (VRE) penetrations will increase spot price variability, presenting opportunities for some users to shift their demand in response to price changes, enabling more dynamic responses to changing supply conditions. The Australian Energy Regulator (AER) plays a key role in monitoring high-price events.[53]

Traditionally, the cost of coal and gas has played a significant role in setting electricity prices due to price inelasticity. However, the emergence of cost-effective, flexible demand-side resources and storage may result in the opportunity cost of storage and demand increasingly playing a role in establishing prices. Electricity users with highly flexible demand have the potential to support efficient price formation by adjusting their consumption in response to market signals. This flexibility can help balance supply and demand, which in turn may lower overall energy costs in the future.[54]

52 While consumers may continue to use electricity, they can use less from the grid when it is expensive because they can produce and store their own electricity.

53 AER (2022), Significant price reporting guidelines, p 3.

54 Briggs et al. (2024), 'Flexible Demand – the Current State of Play in Australia,' Institute for Sustainable Futures, UTS. Report prepared for ARENA.

Examples of initiatives to address barriers to scaling flexible demand

Several initiatives are currently underway to address barriers to scaling flexible demand. AGL is trialling a price intensity forecasting tool that enables commercial and industrial (C&I) users to dynamically shift energy use across 30-minute intervals using seven-day-ahead generation forecasts, allowing participation in price-responsive load flexing without direct wholesale market exposure.[55] EnergyAustralia's PowerResponse program, which evolved from a 2017–21 Australian Renewable Energy Agency (ARENA)-funded trial,[56] now operates commercially, offering residential and small business customers bill credits for reducing electricity use during peak events.[57] Participants are rewarded based on measured reductions against historical baselines, supporting broader engagement in demand-side flexibility.

There are many Virtual Power Plants (VPPs) making efforts to scale flexible demand at the household level. A notable example is the South Australia Virtual Power Plant (SA VPP), established in 2018 as the first VPP in Australia to support grid frequency stabilisation. As one of the largest VPPs in Australia, the SA VPP aggregates distributed solar and approximately 7,000 home batteries installed across social and community housing.[58] It delivers discounted energy to participating households while providing essential grid stability services.[59]

Internationally, large industrial loads are demonstrating the potential for demand-side participation at scale. The Tiwai Point, or New Zealand Aluminium Smelter (NZAS), New Zealand's single largest electricity consumer, has entered contractual arrangements to provide large-scale demand response.[60] This arrangement supports the 20-year operation of the smelter while enabling the system operator to access flexible load, with compensation paid to the smelter for the loss in production volume.[61] [62] During the winter of 2024, NZAS progressively increased its demand response to 205 MW, a 36% reduction in total consumption.[63] This response exceeded the contracted maximum and was instrumental in maintaining system balance, and reducing reliance on more expensive generation during peak winter demand.[64] The Australian Aluminium Council, in their submission to the Draft Report, noted that the ability of industrial facilities to offer demand response services is contingent on site-specific technical and infrastructure characteristics.[65] As such, the replicability of these arrangements across other smelters or large loads requires careful consideration of operational constraints and commercial viability.[66]

55 ARENA (2023), Dynamically managing energy loads for a smarter electricity grid, media release 29 November 2023.
56 ARENA (2021), EnergyAustralia Demand Response Program.
57 EnergyAustralia (2025), PowerResponse demand response program.
58 Government of South Australia, the Department for Energy and Mining (2025), South Australia's Virtual Power Plant.
59 Ibid.
60 In 2023, the smelter consumed the equivalent to 20% of the North Island's electricity use. Electricity Authority Te Mana Hiko (2024), The Tiwai Point smelter demand response in winter 2024, 28 November.
61 Meridian (2024), NZAS contract: Demand Response Agreement, 30 May.
62 Rio Tinto (2024), News Release: Long-term future for NZ's Tiwai Point aluminium smelter secured with new power deals, 31 May.
63 Electricity Authority Te Mana Hiko (2024), The Tiwai Point smelter demand response in winter 2024, 28 November.
64 Ibid.
65 Australian Aluminium Council (2025), submission to the NEM Review Draft Report consultation, p 2.
66 Ibid.

3.2 The energy-only market remains efficient in a highly renewable system

In a system dominated by near-zero marginal cost renewables, there are growing concerns that the market will experience frequent zero or negative prices during periods of surplus renewables and sharp price spikes during renewable output scarcity.[67,68]

A key question is: can the market continue to send clear, efficient price signals that reflect marginal costs in a system dominated by near-zero marginal cost renewable generation? Most stakeholders assert that the energy-only market continues to deliver reasonably efficient operational dispatch in a highly renewable system.[69] The Panel agrees.

> *The potential for price volatility is inherent to the energy-only market design as it enables a highly accurate reflection of the balance of supply and demand, and the level of resource scarcity.*
> **– CS Energy**
>
> *The ability of the energy-only market to reveal system dynamics and convey scarcity in real time is one of its strengths.* **– Snowy Hydro**

The reduced role of fuel costs in high-renewables systems does not necessarily undermine the fundamentals of energy-only markets, provided that storage operations, scarcity pricing and demand response are effectively integrated into market operations.[70] The opportunity cost of storing electricity in batteries or pumped hydro is likely to be an important driver of prices, as there is always a trade-off for how long to store or discharge energy.[71] Even modest demand elasticity can enhance market performance by smoothing out extreme price spikes.[72] This underscores the importance of enabling greater visibility and participation in dispatch of both large-scale and behind-the-meter demand-responsive resources to contribute to efficient price formation (refer to **Recommendation 2**).[73]

[67] Antweiler, W. and Müsgens, F. (2024), 'The new merit order: the viability of energy-only electricity markets with only intermittent renewable energy sources and grid-scale storage', in USAEE Working Paper.
[68] G Thomaßen et al. (2022), 'Will the energy-only market collapse? On market dynamics in low-carbon electricity systems', in Renewable and Sustainable Energy Reviews.
[69] Submissions to the initial NEM Review consultation from CS Energy (p 2), Snowy Hydro (p 5), AFMA (p 2), Iberdrola (p 5), Hydro Tasmania (p 13), ENGIE (p 2), AGL (p 3) and ACEN Renewables (p 2).
[70] T Brown et al. (2025), 'Price formation without fuel costs: the interaction of demand elasticity with storage bidding', in Energy Economics.
[71] Ibid.
[72] Ibid.
[73] Ibid.

Stakeholder feedback on maintaining the energy-only spot market

Stakeholders expressed strong and widespread support for retaining the energy-only spot market as the core market design.[74] Stakeholders generally agreed that the energy-only spot market continues to deliver reasonably efficient operational dispatch[75] and provides a strong foundation for the energy transition.[76] Many noted that the energy-only spot market, in conjunction with forward derivative markets, efficiently allocates existing resources and provides revenue sufficiency for an efficient level of investment – although some stakeholders put forward alternative views.[77]

A small number of stakeholders identified potential inefficiencies and risks in the current market design. These included concerns about the market's preparedness for AI-driven bidding, barriers to deployment of long-duration storage, and the market's limitations in supporting mass integration of flexible demand response.[78]

In response to feedback, the Panel has retained its core recommendation to retain the energy-only market. It considers that using the existing rule change process to support efficient and competitive energy-only spot market operation (**Recommendation 4**) and reforms to improve the visibility and participation in dispatch of price-responsive resources (**Recommendation 2**) will strengthen the continued efficient operation of the energy-only spot market.

3.3 The spot market is sending incomplete signals for investment

The energy-only spot market has generally succeeded in delivering both revenue adequacy and efficiency over short-term operational timeframes – key strengths that should be preserved through the transition. However, as the NEM transitions, there is a growing need for durable, long-term investment signals.

The tenor gap, defined by the Panel as the mismatch between long-term contracts needed by sellers and the short-term contracting of buyers, is a significant factor. Uncertainty around the timing of coal plant retirements, rapid technological changes, demand forecasts and shifting policy settings makes it difficult for investors to assess future market conditions and commit to financing capital intensive long-term projects.

To address this, the Panel has proposed targeted reforms, including the Electricity Services Entry Mechanism (ESEM) (**Recommendation 10**), to provide durable, long-term signals while preserving the efficiency and integrity of the real-time energy-only spot market.

[74] Submissions to the NEM Review Draft Report consultation supporting the recommendation to retain the energy-only spot market include ACEN, ActewAGL, AEMC, AEMO, AER, AFMA, AGL, Akaysha, Ausgrid, Australian Energy Council, BlueScope, CEIG, Clean Energy Council, CleanCo, CS Energy, Delta, EDF, Eku Energy, EMX Energy, ENA, ENGIE, EUAA, Fluence, Flow Power, Genuity, Hydro Tasmania, Hydrostor, Iberdrola, Justice and Equity Centre, Nexa Advisory, Origin Energy, Potentia Energy, Smart Energy Council, Snowy Hydro, Squadron Energy, Tesla, Productivity Commission, Tilt Renewables and Transgrid.

[75] Submissions to the NEM Review initial consultation include CS Energy (p 2), Snowy Hydro (p 5), AFMA (p 2), Iberdrola (p 5), Hydro Tasmania (p 13), ENGIE (p 2), AGL (p 3) and ACEN Renewables (p 2).

[76] Submissions to the NEM Review Draft Report consultation include AGL (p 2), AEC (p 6) and AEMC (p 1).

[77] Submissions to the NEM Review Draft Report consultation from Changing Weather (p 7) and Tiho Ancev and Songze Qu (p 1). AEMC (2025) submission to the NEM Review Draft Report consultation (p 5) outlined the issue of revenue insufficiency for VRE technologies.

[78] Submissions to the NEM Review Draft Report consultation from Tiho Ancev and Songze Qu (p 1), LDES Council (p 1) and Enel X (p 3).

> Recommendation 1A: Retain the real-time regional energy-only spot market with necessary rule changes to ensure its continued efficient and competitive operation, recognising that increasing spot market price variability and volatility can be managed.

3.4 Incremental reforms to the well-functioning spot market can manage factors impeding efficient operation

As the NEM undergoes fundamental changes to its generation fleet, factors impeding efficient operation and price discovery may become more prominent. However, these factors can be addressed with incremental reforms such as requiring a broader range of price-responsive resources to be visible or participate in dispatch (**Recommendation 2**).

To preserve the efficiency and competitiveness of the spot market, the Panel recommends retaining its core design while making targeted rule changes as required (**Recommendation 4**). This includes understanding the risks and opportunities created by algorithmic bidding to inform regulatory responses, assessing the adequacy of battery state of charge information and reducing transmission outage impacts on spot market efficiency.

3.5 Consumers must be supported to respond to or manage price risk

As the energy mix becomes more energy-constrained and weather-dependent, spot price signals are expected to sharpen. This increased price and earnings volatility for market participants will increase the importance of responding to, or managing, risk for consumers and generators.[79]

As prices become more variable, demand flexibility can play a greater role in smoothing out demand troughs and peaks. The full benefits of price-responsive resources in meeting market needs will only be unlocked when these resources are visible to the market. This visibility enables more efficient spot price formation, promoting grid stability, competition and investment. The Panel acknowledges the potential cost of failing to effectively integrate responsive resources into the market and has recommended reforms to support consumer outcomes (**Recommendation 2**).

A well-functioning derivatives market, characterised by transparent pricing, robust competition and deep liquidity, is essential for translating volatile spot signals into investable, forward-looking price information.[80] Increased year-to-year variability as weather increasingly drives price outcomes, particularly over winter, will affect retail electricity prices, underscoring the importance of retailers engaging in longer-term risk management to smooth wholesale volatility for consumers. While derivatives markets are adjusting to changes in the NEM, the pace has been too slow. The Panel acknowledges the need for market participants to manage price risk effectively and has recommended reforms to support consumer outcomes (see **Chapter 4: Maintaining liquidity in the derivatives market**).

[79] Hirschhorn et al. (2022), 'Is electricity pricing running out of gas?', Boston Consulting Group article.
[80] Submissions to the initial NEM Review consultation from CleanCo Queensland (p 3), Iberdrola (p 6) and ENGIE (p 2).

3.6 System security directions are increasing costs for consumers

The physical characteristics of the system are evolving as VRE replaces synchronous generators that traditionally provided essential system services (ESS) to the grid. Without alternative sources of inertia, system strength and voltage support, AEMO must dispatch legacy thermal units, even when these are not the lowest-cost energy sources.[81] These out-of-merit-order directions have increased in frequency and cost over recent years with these costs ultimately borne by consumers. In South Australia, the cost of these directions is becoming a material and growing proportion of consumer bills.[82]

As synchronous units have physical characteristics that support grid stability, shifting towards more asynchronous, inverter-based VRE means grid stability must be provided in other ways. Several reforms underway are designed to address these issues, and the ESEM presents a further opportunity to deliver ESS capabilities at lower cost (**Recommendation 10B**).

> Recommendation 1B: Do not create additional mandatory centralised short-term (operational timeframe) markets, such as capacity markets or physical ahead markets

3.7 The existing energy-only market maintains reliability over operational timeframes

Some stakeholders argue that spot price signals are becoming less effective in providing revenue certainty for generation. Concerns have been raised that the energy-only spot market is struggling to deliver sufficient long-term price signals to support timely and efficient investment, leading to suggestions for alternative models. Several stakeholders proposed introducing a capacity market in the NEM Review initial consultation, similar to the capacity mechanism proposed by the Energy Security Board in 2021.[83] The intention behind introducing a capacity market is to provide a mechanism that ensures generation is available when called upon, supporting revenue sufficiency and consistency for dispatchable generation.

However, the existing energy-only spot market already provides strong real-time scarcity signals through a high MPC that is aligned with the Value of Customer Reliability (VCR).[84] These sharp price signals reward participants that can supply energy when it is most needed and enable generators to recover fixed costs during periods of scarcity. Conversely, participants that fail to deliver when required face high spot prices, particularly if they have forward-sold their capacity. Few alternative market designs can replicate these efficient incentives for reliability, especially as new, flexible technologies such as batteries become more prevalent.

81 AER (2024), State of the energy market 2024.

82 The Compensation Recovery Amount as a proportion of the Default Market Offer (DMO) wholesale cost for residential and small business customers has increased from 3% in 2020–21 to 5% in 2022–23 in South Australia. AER (2024), Wholesale electricity market performance report 2024, 20 December, p 138.

83 Submissions to the initial NEM Review consultation include Australian Pipelines and Gas Association, Potentia Energy, Hydro Tasmania, Origin Energy, Shell Energy, Alinta, Energy Users Association of Australia, Centre for Independent Studies, Stanwell Corporation, CleanCo Queensland and Delta.

84 The Value of Customer Reliability (VCR) indicates the value different types of customers place on having reliable electricity supply under different conditions, measured in dollars per kilowatt hour. In the NEM, VCRs are used by the Reliability Panel in conducting the reliability standard and settings review and by the AER and network service providers in a variety of network regulation and planning processes. AEMC (2018), Establishing values of customer reliability.

The NEM also features a well-established cap contract market that allows participants to manage risk and smooth revenue, supporting revenue consistency for market participants. This market is effectively a decentralised capacity market. Participants actively use these markets to hedge against price volatility.

These features of the energy-only spot market deliver the key outcome that capacity markets are designed to provide over operational timeframes: reliable capacity that meets reliability standards. The Panel believes an energy-only spot market will continue to provide these outcomes in a renewable-dominated and high-opportunity-cost system. Neither energy-only markets nor short-term capacity markets alone are sufficient to incentivise the necessary investment during the transition, as neither overcomes the tenor gap. International experience shows that once a market design is chosen, the most effective approach is to build on that foundation, addressing emerging challenges through targeted reforms rather than pursuing major market redesign (see discussion of international challenges in other energy markets in **Chapter 2: Trends and challenges in the NEM**). Given this, the Panel has prioritised targeted reforms that support the existing system rather than fundamentally restructuring it.

Stakeholder feedback on other mandatory centralised short-term (operational timeframe) markets

A limited number of stakeholders raised the introduction of physical day-ahead markets to improve certainty and coordination in the NEM in response to the Panel's initial consultation.[85] Of the small number of stakeholders who responded to the Draft Report consultation, most were supportive of the Panel's recommendation to not create additional markets, including physical day-ahead markets.[86]

Physical day-ahead markets are markets where market participants purchase and sell energy at financially binding day-ahead prices. A system operator uses this information to create a schedule of commitments for the purchase and sale of energy for the following day according to bid and offer data from participants. Day-ahead markets are accompanied by a real-time or balancing energy market, to account for variations in supply and demand between the day-ahead schedule and actual market conditions at the time of dispatch.

Some stakeholders highlighted barriers for price-responsive consumers and dispatchable loads to optimise load with sufficient notice (see **Recommendation 2**). International examples, like the day ahead market in the PJM Interconnection, aim to provide electricity service providers with greater predictability and notice for participation. However, even markets with day-ahead trading, such as the California Independent System Operator (CAISO) or the Electricity Reliability Council of Texas (ERCOT), are relying on additional investment support by government through long-term contracts or state funding programs.

While the Panel recognises the potential benefits of short-term ahead markets for some participants, these services can be provided through financial markets, where innovation is already occurring. Furthermore, resources requiring very significant notice to respond to conditions may not necessarily be as economic in an increasingly weather-dependent system where flexibility and fast response is most valuable.

85 Submissions to the NEM Review initial consultation include ENGIE (p12) who noted customers may be more willing to participate with price-pass-through products if the risk of extremes were suppressed, for example through a day-ahead market and Tesla who referenced research which noted that hybrid markets can meet requirements in delivering capacity (p 8).

86 Submissions to the NEM Review Draft Report consultation include AFMA (p 1), AGL (p 2), Akaysha (p 4), Fluence (p 4), Flow Power (p 3), Iberdrola (p 1), Nexa Advisory (p 6), Origin Energy (p 4) and Snowy Hydro (p 2).

Recommendation 1C: Do not implement locational marginal pricing (LMP) or variants considered previously

3.8 The cost of implementing LMP, and other variants recently considered by the Australian Energy Market Commission (AEMC), would likely exceed the benefits and would not provide certainty to market participants over investment timeframes

The NEM was designed with zonal/regional pricing, where price formulation and market functions occur in relation to a designated reference node in each region.[87] The combination of open access, regional pricing and central dispatch can result in both operational and investment inefficiencies, particularly under constrained conditions. By applying a uniform regional price across each zone, the NEM can misprice generation when there are transmission constraints, leading to financial outcomes for participants that diverge from the true marginal value of their actions.[88] To partially address this, the NEM incorporates marginal loss factors (MLFs) as a core feature of the locational pricing framework. MLFs reflect marginal transmission losses between generation and regional reference nodes, which are applied in market settlement. MLFs provide a financial signal that helps guide efficient investment in generation and storage and discourages development in locations that would increase system losses.

LMP is a core feature of many international electricity markets, designed to reflect the true cost of supplying electricity at different points on the grid by incorporating both generation costs and network congestion. It is most effective in systems with varying marginal costs, such as those dominated by coal and gas. For example, where a constraint limits flows from a region with low-cost coal (e.g. $50/MWh) to one relying on higher-cost gas (e.g. $150/MWh), LMP results in higher prices on the constrained side, signalling scarcity and the value of local generation.

This dynamic changes dramatically in the context of a decarbonised grid dominated by wind and solar. With most renewable generators bidding at or near-zero SRMC, the system cannot distinguish economically between them during periods of constraints. While LMP still reflects scarcity on the constrained side, it may no longer provide meaningful dispatch signals or guide efficient investment. LMP in this context becomes less useful as a tool for driving efficient short-run outcomes or long-term investment signals. However, evidence from the wholesale electricity market in ERCOT shows that LMP could provide greater operational efficiency benefits by incentivising more efficient bidding by storage in congested areas.[89]

[87] Zonal pricing (also known as regional pricing) refers to setting of wholesale prices at a single regional reference node in each NEM jurisdiction. Nodal pricing refers to setting of prices at each node on a network. There are typically hundreds of nodes on a transmission network. Further information is available at AEMC (2024), Final report volume 3 of 3: Transmission access reform: Access and pricing in the NEM, p 1–3.

[88] M Katzen & G Leslie (2024), Siting and operating incentives in electrical networks: a study of mispricing in Australia's zonal market in International Journal of Industrial Organization.

[89] Potomac Economics (2025), 2024 State of the Energy Market Report for the ERCOT Electricity Market, p 52.

The limitations of market mechanisms in transmission investment

LMP is a core feature of many electricity markets, designed to signal the true cost of delivering electricity at different locations by accounting for both generation costs and network congestion.

LMP works effectively when there is a diverse set of generators with varying marginal costs distributed across the network. Take, for example, the traditional grid dominated by coal and gas. Suppose there is a transmission constraint between two regions: Region A with low-cost coal generators (e.g. $20/MWh) and Region B that relies on higher-cost gas generators (e.g. $80/MWh). When the transmission line becomes constrained, Region B must meet its own demand using more expensive local generation. As a result, the LMP in Region B rises significantly, accurately reflecting the cost of local supply and the value of scarce transmission capacity. This price signal incentivises more efficient dispatch, demand-side response and potentially local investment to relieve the constraint.

However, this dynamic changes dramatically in the context of a decarbonised grid dominated by wind and solar. These renewable generators have effectively zero short-run marginal cost, meaning they all bid into the market at or near $0/MWh. Imagine now that Region A and Region B are both rich in solar resources, and a constraint emerges between them. Behind the constraint, say in Region A, there may be 500 MW of solar generation, but the transmission line can only carry 300 MW. With all solar generators bidding in at $0, the system has no economic basis to prefer one over another; they are indistinguishable from a cost perspective. As a result, LMP still rises on the constrained side (Region B), reflecting scarcity, but it does little to guide efficient dispatch or signal which generator should be built or curtailed. There is no marginal cost variation to exploit. LMP in this context becomes less useful as a tool for driving efficient short-run outcomes or long-term investment signals.

Some argue that financial transmission rights (FTRs), which pay out based on price differences between nodes, can address this problem by providing a hedging instrument for congestion risk. In theory, FTRs reward holders when there is a price difference between two locations, which could provide an incentive to build generation in congested areas or fund transmission upgrades. However, in practice, FTRs have limitations. First, they are typically auctioned or allocated for relatively short durations, one to three years at most. For example, while useful for managing locational price risk, market participants in New Zealand report that the two-year FTR market provides limited value for long-term investment decisions, with no generators citing them as directly enabling investment in new generation.[90] This timeframe is far too short to underpin the kind of long-lived capital investment required to build new transmission infrastructure or large-scale generation and storage. Second, FTRs are purely financial instruments; they do not confer physical access to the grid or rights to dispatch.

The issue of zonal versus nodal pricing has been considered internationally. For example, the UK Government has recently concluded that while zonal pricing could address wholesale market challenges, its risks to investor uncertainty for Contract for Difference-backed generators, distributional fairness and long delivery timeframes, outweigh its benefits.[91] Instead, the UK

[90] NZ Electricity Authority (2023) financial transmission rights Market review: Decision paper, Appendix B, p 48.
[91] UK Government (2025), Review of the Electricity Market Arrangements (REMA): Summer update, 2025

Government has opted for reforms to national pricing, as they involve significantly less disruption and can deliver benefits to consumers sooner than would be possible under zonal pricing.[92]

This same issue has been considered numerous times since the NEM's inception. While many reviews have recommended LMP or similar approaches, these reforms have not been adopted, with decisions ultimately retaining the zonal market design. Most recently, the AEMC completed its transmission access reform review in 2024, recommending against implementing the hybrid access reform model. The AEMC concluded that the benefits of priority access to improve investment efficiency and certainty over and above what can be achieved through jurisdictional schemes, if delivered effectively, would likely be marginal.[93] It was determined that the congestion relief market, which is complex and contains a number of design compromises, creates uncertainty about whether potential benefits would materialise and outweigh the costs of implementation.[94] The Panel has not pursued LMP as part of this review, as LMP and related transmission access reforms were recently ruled out by energy and climate ministers in 2023.[95]

Under current market settings in the NEM, generators operating in congested areas can develop solutions for managing constraints through investment in flexible resources. By co-locating storage behind the congestion point, generators can smooth output during peak congestion periods, improve access to higher market prices, and reduce curtailment risks. These arrangements can create mutual benefits: generators increase their revenue certainty and asset utilisation, while the shared infrastructure spreads costs and improves the overall efficiency of grid utilisation. Virtual transmission[96] can also increase the effective capacity of the existing transmission system by placing batteries near demand centres. Transmission network service providers (TNSPs) can contract these batteries to boost line ratings and safely move more energy through the network, deferring or avoiding the need for physical infrastructure upgrades. These strategies demonstrate how the market can work to respond to network congestion, finding effective solutions without the need for locational marginal pricing.

As noted above, the policy response to the mispriced signals for investment associated with the current zonal market design is the development of Renewable Energy Zones (REZs) by individual NEM jurisdictions. While implementation varies, REZs typically allocate defined network capacity to new renewable generation and storage projects based on expected generation and load profiles.[97] In principle, this approach helps reduce the risk of inefficient or duplicative network investments by providing a framework for coordinated decentralised investment.[98]

92 Ibid.
93 AEMC (2024), Final report: Volume 1 of 3, September. Transmission access reform.
94 Ibid.
95 Energy and Climate Change Ministerial Council (2023), 24 February Meeting Communique.
96 Virtual transmission refers to financial or non-network mechanisms that replicate the economic or operational effects of physical transmission capacity, for example energy storage systems used in place of transmission capacity. K Kumaraswamy, A Sondhi, P Barrague and H Wolfschmidt (2020), Building Virtual Transmission: Critical elements of energy storage for network services, a white paper for Fluence Energy.
A small number of stakeholders noted the advantage of virtual transmission in submissions to the NEM Review draft consultation, including Akaysha (p 4), CEFC (p 5), Fluence (p 4) and Tesla (p10), and Wonhas and Coles (p 7).
97 Ibid.
98 P Simshauser (2025), 'Competition vs. coordination: optimising wind, solar and batteries in renewable energy zones', in Energy Economics.

Stakeholder feedback on locational marginal pricing

In the initial consultation, some stakeholders proposed implementing LMP to address concerns that a lack of locational signals in the NEM could lead to over-investment in generation and network infrastructure beyond what consumers value.[99]

Following the Panel's draft recommendation to not implement LMP or variants, a small number of stakeholders provided further feedback. Most of these stakeholders supported the Panel's recommendation, noting LMP has been considered extensively in previous reviews.[100]

However, a limited number of stakeholders raised concerns that regional pricing in the NEM contributes to market inefficiencies by failing to reflect local marginal costs and benefits, particularly under network constraints.[101] For example, under regional pricing there is over-investment of intermittent resources in congested areas of the network and under-investment of storage assets in more congested areas.[102] The Monash Energy Institute and Energy Consumers Australia advocate for a progressive transition to LMP to improve dispatch efficiency and guide storage investment in the NEM, leading to a more efficient use of constrained generation and lower long-term system costs.[103]

The Panel has considered stakeholder feedback and retained its draft recommendation to not implement LMP. The Panel notes the potential role of REZs and virtual transmission initiatives in managing congestion in the NEM.

[99] Submissions to the initial NEM Review consultation from Centre for Independent Studies (p 8), Energy Consumers Australia (p 5), Greg Williams (p 4) and Reposit Power (p 4).

[100] Submissions to the NEM Review Draft Report consultation include AusNet (p 1), CEIG (p 4), CS Energy (p 3), Flow Power (p 3), Fluence (p 4), Productivity Commission (p 3), Origin Energy (p 4) and Snowy Hydro (p 2).

[101] Monash University Energy Institute (2025), submission to the NEM Review Draft Report consultation, p 4, 13–14.

[102] M Katzen & G Leslie (2024), Siting and operating incentives in electrical networks: a study of mispricing in Australia's zonal market in International Journal of Industrial Organization.

[103] Submission to the NEM Review Draft Report consultation from Monash University Energy Institute (p 4) and Energy Consumers Australia (p 6).

Recommendation 1D: Do not create distribution-level wholesale energy markets. Instead, facilitate distribution-level energy resources to participate in regional markets and use dynamic operating envelopes (DoEs) and dynamic network tariffs to manage local constraints

3.9 Integrating CER within the existing market is preferable to creating new distribution-level wholesale markets

The need and potential options for real-time energy markets at the distribution level were explored through the National CER Roadmap.[104] The majority of stakeholders providing feedback through that process considered that the costs of real-time distribution-level markets would outweigh the benefits. Stakeholders noted that aggregated CER will have the option to be integrated into the wholesale market as voluntarily scheduled resources (VSRs) from 2027. Stakeholders considered that in addition to embedding the arrangements for VSRs, the focus should be on developing and scaling up the use of distribution-level tools (DOEs, dynamic network prices and flexibility services) as a way of organising unscheduled CER at the distribution level.

The Panel does not see the creation of a separate distribution-level wholesale energy market as a necessary reform. This approach would likely involve significant implementation costs and add complexity for participants engaging across multiple markets and regions, potentially having negative consequences for competition. The Panel considers that the NEM is already evolving to integrate CER within the existing market framework and that work on developing separate distribution-level wholesale markets would divert resources away from this.

Rather than pursuing structural redesign, the Panel has focused on accelerating this evolution through targeted reforms that enable CER participation to contribute to greater market efficiency. This includes integrating distribution-level resources into the existing regional market framework (see **Recommendation 2**). This would be supported by dynamic operating envelopes and network tariffs to manage local constraints efficiently. The Panel has considered other aspects of the roadmap in **Recommendation 3**.

Stakeholder feedback on distribution-level markets

While only a small number of stakeholders provided feedback on distribution-level markets discussed in the Draft Report, the majority were supportive of the recommendation to not create distribution-level markets.[105] They agreed that the complexity and cost would outweigh the benefits, and that the immediate focus should be integrating CER within existing market arrangements.[106]

[104] Consultation opened 9 July 2025 on the CER Roadmap workstream M3/P5 – Redefine roles for market and power systems operations and closed on 20 August 2025. A final report on this workstream will be considered by energy ministers in December 2025.

[105] Submissions to the NEM Review Draft Report consultation include Ausgrid (p 1), AusNet (p 1), Clean Energy Council (p 14), CS Energy (p 3), Energy Efficiency Council (p 14), Energy Networks Australia (p 3), Ergon and Energex (p 1), Justice and Equality Centre (p 12), Origin Energy (p 4), Solar Citizens (p 5), Snowy Hydro (p 1) and SA Power Networks (p 1).

[106] Submissions to the NEM Review Draft Report consultation from AusNet (p 1), Energy Networks Australia (p 3) and Origin Energy (p 4).

Recommendation 2: Energy ministers should require that a wider range of price-responsive resources (PRR) are visible or participate in dispatch so they can contribute effectively to market price formation

As explained in **Chapter 2: Trends and challenges in the NEM**, the NEM is transforming rapidly into a system dominated by weather-dependent bulk VRE resources and an expanding fleet of CER, DER and demand response resources. These decentralised and price-responsive resources (PRR) will play an increasingly vital role in delivering bulk energy and shaping services in the NEM. As their scale and influence grow, so too does the need to ensure they operate in ways that support the efficient functioning of the NEM. While consumers and businesses that respond dynamically to price signals can benefit directly, broader market benefits will only be realised if these resources are visible to the market and able to participate effectively. If the market does not accommodate their participation in forecasting and price formation, the market will become increasingly inefficient, unstable and costly.

As high-capacity factor thermal generation exits, accurate price signals from demand flexibility and distributed resources will become increasingly important for overall price formation in the spot market.

Defining demand flexibility, DER, CER and VPPs

Demand flexibility: Demand flexibility is the ability of electricity consumers to adjust their electricity use in response to grid conditions or price signals, reducing strain on the network during peak times. Examples include shifting loads to off-peak hours, shedding non-essential loads, shaping load profiles, modulating usage dynamically, managing multisite loads, and providing fast, short-term responses to grid needs. To unlock value for consumers from this flexibility there is a range of spot-price pass-through retail offerings in the market.

Distributed energy resources (DER): DER include small-scale energy resources such as generators, battery storage and electric vehicle (EV) charging facilities. Consumer energy resources (CER), a subset of DER, are located at consumer sites and include rooftop solar, batteries, EVs and controllable devices like smart appliances.

Virtual power plants (VPPs): VPPs aggregate DER to provide grid services traditionally provided by conventional power plants. They offer benefits like contingency services, energy market participation, cost reduction and network support, improving grid reliability and efficiency. Different VPPs may pass on consumer benefits in different ways, such as fixed payments, participation incentives or lower energy costs. As part of these differences, VPPs may have varying levels of control over consumer resources, which affects their predictability. Some VPPs may have fully remote automated control and be able to deploy their demand response with precision and speed, particularly with technologies such as household batteries.

3.10 Hidden resources are distorting forecasts, raising system costs and weakening investment signals

> *... without this visibility and with rapidly expanding CER, the market operator is flying the plane with one eye closed* – **EUAA**[107]

Shifting away from the NEM's foundational gross pool model: The NEM was designed as a gross pool with energy derivative markets to manage risk. However, the current obligation to participate in the gross pool applies only to generation above 30 MW and batteries above 5 MW, with no participation obligation on the demand side or small resources. As large, centralised resources are replaced with smaller, decentralised resources (not obliged to participate in the gross pool), the market is shifting towards a net pool. In the absence of explicit policy decisions, this creates gaps in market participation and price formation.

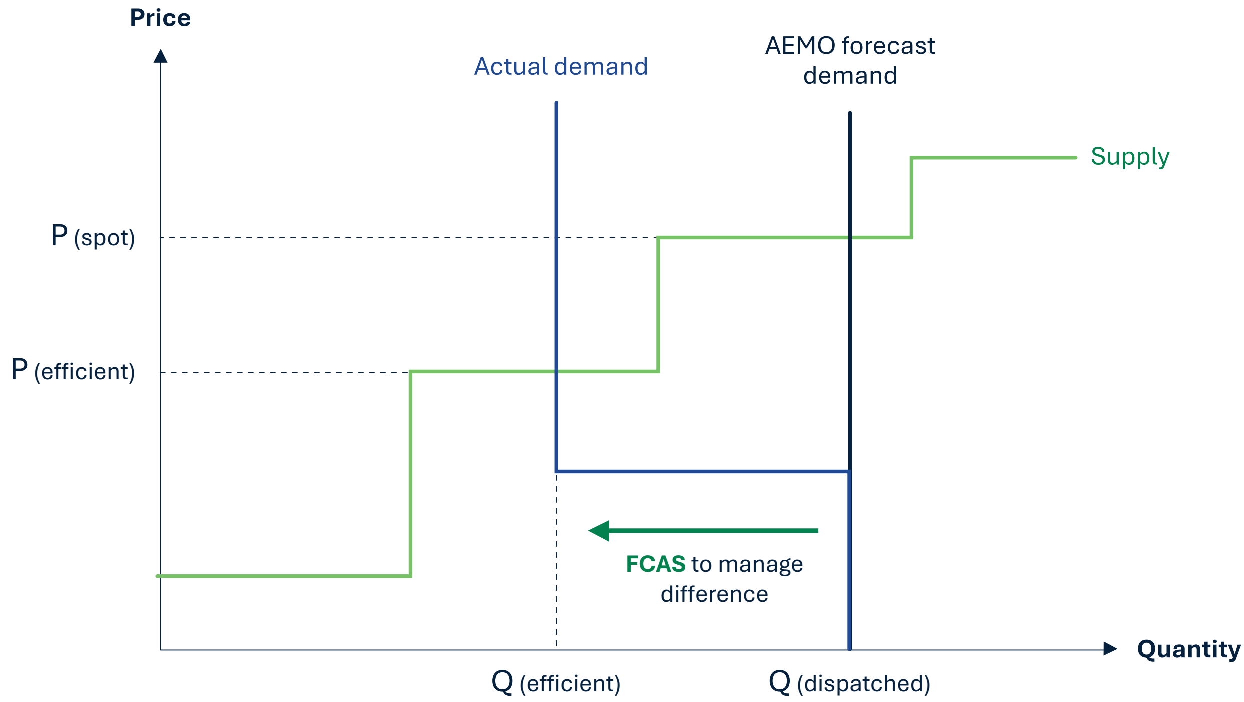
Hidden participants result in mis-forecasting and inefficient price formation: PRR that are not visible to the market operator and other participants create significant impediments to efficient market operation. This lack of visibility means AEMO and market participants cannot accurately forecast how DER and large-scale demand will respond to price changes. As outlined in the AEMC's Integrating Price-Responsive Resources (IPRR) final determination, the lack of visibility of price-responsive CER, DER and demand flexibility can lead to AEMO routinely over/under-forecasting demand and dispatching more/less supply than is necessary.[108] This results in higher-than-necessary investment in electricity services and higher-than-necessary dispatch prices in wholesale markets.

Increased FCAS costs: The lack of visibility and participation by PRR increases the need for frequency control ancillary services (FCAS) to balance mis-forecasting within a five-minute dispatch interval, creating inefficient excess FCAS costs.[109] These costs are an externality of PRR because FCAS costs caused by forecast errors related to hidden participants are recovered from all consumers. This is different to large generators, who are subject to individually calculated frequency performance payments.

Figure 34 illustrates when resources unexpectedly reduce demand or increase supply in response to price, AEMO will typically over-forecast demand and over-dispatch generation. To balance supply with actual demand levels FCAS is required to address the short-term imbalance. As a result, spot prices are higher than needed, more generation is dispatched than needed and higher FCAS costs are required to redress the inefficiency in price formation and dispatch.[110]

[107] EUAA (2025), submission to the NEM Review Draft Report consultation, p 4.
[108] AEMC (2024), National Electricity Amendment (Integrating price-responsive resources into the NEM) Rule 2024, Final Determination, 19 December 2024, p 12.
[109] Ibid.
[110] Op Cit., p iii.

Figure 34 – Inaccurate demand forecasts cause higher than efficient spot prices, and increase generation and FCAS costs



Source: AEMC (2024), National Electricity Amendment (Integrating price-responsive resources into the NEM) Rule 2024, p iii.

Increasing uncertainty and risk: Market inefficiencies that cause less accurate short-term forecasts can, in turn, increase the risk of participation for demand-responsive loads and investment in PRR. Price-responsive loads and resources may be hesitant to participate due to uncertainty around demand (and therefore price) forecasts. Uncertainty around demand forecasts fundamentally undermines the business model for deploying more price-responsive loads and resources.

Poorer signals for long-term investment: The lack of visibility and participation of PRR results in less accurate long-term forecasting by AEMO and investors. Poor integration of CER, DER and demand flexibility into the market may ultimately result in inefficient over-investment in centralised resources and peaking plants. By using resources that already exist to meet demand, rather than investing in peak capacity that is seldom used, demand flexibility and DER can reduce the development cost of centralised generation assets that must be recovered from consumers over the long run.

Why is this an issue now when price-responsive resources have always existed?

Demand response has always been a feature of the NEM. Many C&I users have contracts in place that reduce demand by a prescribed amount when prices exceed a particular threshold (e.g. $300/MWh). These static[111] price-responsive loads can display consistent demand response patterns that are observable in the market and, in some cases, can be used to predict their likely behaviour.

However, the landscape is changing with the rapid proliferation of distributed batteries and more dynamically price-responsive resources. Australian households and small businesses are embracing small-scale batteries. The Clean Energy Regulator reported that from 1 July 2025 (when solar batteries became eligible under the Small-scale Renewable Energy Scheme) to 31 October 2025, a total of 79,703 solar batteries with VPP capability had been installed with a new or existing rooftop solar system within the NEM.[112] These batteries have an estimated usable storage capacity approximately equivalent to the installed capacity of the Waratah Super Battery in New South Wales.[113]

While the current VPP participation rate is below 20%, AEMO's Inputs, Assumptions and Scenarios Report for the 2026 Integrated System Plan (ISP) expects controllable (aggregated) embedded storage to grow to 32% VPP participation by 2030 and just over 50% by 2050 in their 'Step Change' scenario, representing approximately 14.3 GW.[114]

When aggregated, these dynamic resources operate differently from static ones. They constantly reassess the optimal time to inject power into or withdraw power from the grid as factors such as the opportunity cost of storage vary in each 5-minute interval. This behaviour makes them difficult for AEMO to forecast because their actions are constantly changing based on real-time conditions.

This unpredictability can lead to significant market inefficiencies and increased costs. To mitigate these challenges, it is necessary for these dynamic resources to inform the market of their intentions at different price points. Failing to address this issue would have a similar effect to allowing a large thermal power station to ignore AEMO's dispatch instructions and inject power regardless of whether the system needs it. This lack of visibility can lead to over-supply or under-supply situations, resulting in higher costs and reduced market efficiency.

[111] In this report, static price-responsiveness refers to resources that respond to the same price. Dynamic price-responsiveness refers to resources that constantly change the price at which they will respond.
[112] CER (2025), Installation numbers for small-scale systems by state/territory, Table 8.
[113] CER (2025), Postcode data files SGU Battery Capacity.
[114] AEMO (2025), 2025 Input, Assumptions and Scenarios Report, p 87.

3.11 A range of barriers discourage C&I participation in the market

Many large electricity users already respond to price signals, but this demand response is typically invisible to the market. The Panel's focus is therefore not on the practical ability of large loads to respond to price signals but on addressing the barriers that prevent these resources from being visible in the market, where their contribution can support significant system-wide benefits and consumer outcomes.

Extensive engagement by the Panel with C&I users, their retailers and aggregators found that a significant amount of demand response is already occurring. While some C&I users face operational barriers to participating in demand flexibility, the major barriers ultimately come down to financial risk, set-up and ongoing operational costs, and revenue certainty.

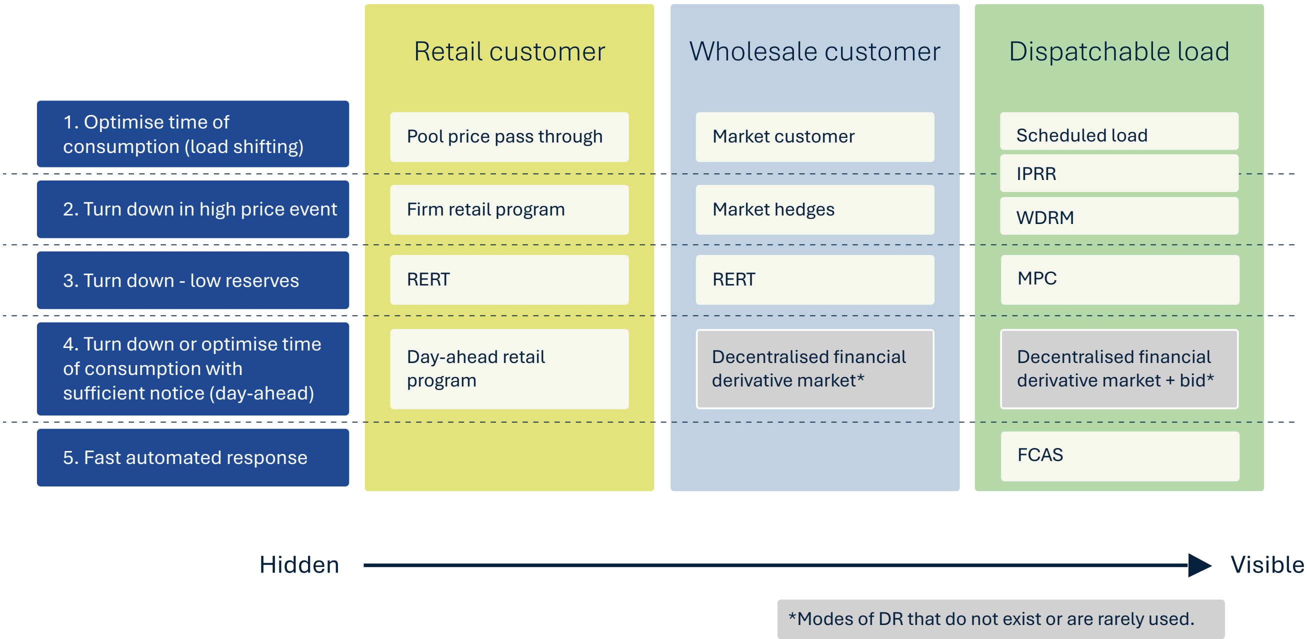
- **Business focus:** C&I users stated that energy trading and demand flexibility are secondary to their core business. Active participation in central dispatch would require building additional in-house capabilities, with the costs potentially outweighing the benefits.[115]
- **Preferences for indirect engagement via retailers:** C&I users expressed a preference for retailer-led demand response models, where participation remains at the customer's discretion and is based on informed trade-offs between risk and reward. In such arrangements, the retailer assumes market obligations (including communicating customer intent to AEMO) while the customer accepts a lower return in exchange for reduced complexity and risk exposure.
- **Costly to participate:** Some C&I users commented that setup and compliance costs required to participate in existing mechanisms that provide greater visibility and/or dispatchability, outweigh the potential benefits they accrue. Some C&I users choose to participate in the short-notice Reliability and Emergency Reserve Trader (RERT) framework, as it allows them a higher degree of flexibility, more certainty and lower costs to participate.
- **Financial risk:** Some stakeholders noted that as pre-dispatch is not a true forecast of price outcomes, it is difficult to rely on for operational decisions. In some cases, this uncertainty of actual spot prices, and the financial risk associated with reducing demand, can deter flexible response.
- **Operational control and safety:** Some stakeholders' feedback indicated that their business was unable to participate directly in the market due to the need for total control over their load for safety reasons. Others expressed the difficulty in responding in real time, noting that more notice would be required to match their longer operational timeframes (e.g. various teams in different locations would need to be notified to carry out multiple switches on different machines in sequence).

> *BlueScope's internal network is a complex mix of assets that have varying levels of price responsiveness. These assets sit behind a set of market facing meters, and as such there would need to be significant augmentation and capital updates to enable the ringfencing of price responsive assets.* **– Bluescope**[116]

[115] Energy Consumers Australia (2023), Submission to the AEMC on integrating price responsive resources into the NEM, p 6.
[116] Bluescope (2025), submission to the NEM Review Draft Report consultation, p 8.

Figure 35 shows the processes that C&I users employ in their demand response and the mechanisms or contracts available to return value. The Panel has identified there are mechanisms available to participate in demand response in various situations as either a retail customer, wholesale customer or as dispatchable load. However, one exception is the ability for a C&I user or dispatchable load to turn down or optimise time of consumption with sufficient notice. Decentralised financial derivative markets would fill this gap and meet the needs of some price-responsive consumers that need sufficient notice to be able to respond. Innovation is occurring to develop these markets, with the emergence of products like TOD Markets' week ahead contracts. Derivatives market innovation is discussed more in **Chapter 4: Maintaining liquidity in the derivatives market**.

Figure 35 – Visibility of price-responsive C&I resources across different modes of participation



Most demand response occurs via mechanisms that are not visible to the market operator

While the NER provides mechanisms for C&I users to offer visible and participative demand response, most demand response does not participate in these existing mechanisms.

Introduced in 2021, the wholesale demand response mechanism (WDRM) allows large electricity consumers to engage in the wholesale market by reducing energy use during periods of peak demand. However, the mechanism is voluntary and has seen limited uptake with only two participants currently involved, comprising 155 MW of participative load.[117] The AEMC has recently reviewed the effectiveness of the WDRM, with its final report recommending that the WDRM should continue operating with further reforms to expand eligibility to users that are served by multiple connection points.[118]

Stakeholder feedback to the NEM Review has highlighted several barriers to participation, including complexity in establishing accurate baseline methodologies and ongoing compliance, lack of awareness from C&I users and a perceived lack of revenue opportunities compared to the costs and risks of participation.

Similarly, the scheduled load participant category has seen limited engagement. The only resources currently registered are storage assets. Stakeholders have confirmed that there is little incentive for any C&I users to register due to the lack of perceived benefits and the complexity of compliance.

While some larger C&I users participate directly in the NEM as market customers, these participants are not required to provide demand forecasts or indicate the responsiveness of their load to the wholesale price.

3.12 Dynamic price-responsive CER delivered through retail contracts is growing

Many consumers prefer simple, easy-to-understand retail arrangements for participating in demand response. This has paved the way for retailers and aggregation services to play a crucial role in translating complex real-time drivers of cost savings into simple offers like bill discounts, lower prices or multi-year fixed-price contracts.

Retailer feedback attributes the success of demand response programs and VPP participation to consumers' ability to retain control of their own resources and consume electricity when they want to. However, retailers are under no obligation to inform AEMO of load behaviour under their CER demand response programs. Similarly, rooftop solar owners are paid for exports per their retail contracts and exports are not visible and do not participate in dispatch.

Therefore, the Panel has recommended that any new obligations for greater market visibility and participation in dispatch should be placed on aggregators and retailers rather than individual consumers, regardless of how consumers choose to operate their CER.

[117] AEMO (2025), NEM Registration and Exemption List.
[118] AEMC (2025), Review of the Wholesale Demand Response Mechanism (Draft Report), p i–iii.

With battery uptake forecast to continue to rise significantly, effectively integrating household battery storage into the NEM wholesale market could significantly benefit consumers. However, if this is poorly managed, significant amounts of small-scale storage interacting with the grid could create issues similar to those caused by rooftop solar, compromising efficient operation of the market and increasing costs to manage system security risks. The Panel's recommendations aim to pre-emptively address these issues, so these new resources deliver maximum benefit to consumers without imposing any new obligations on individual consumers.

3.13 The market needs to enable and encourage visibility and participation

Demand flexibility and distributed resources encompass a wide range of participants, who behave differently. The Institute for Energy Economics and Financial Analysis (IEEFA) estimates that demand response and VPP storage in the NEM already totals about 2.4 GW.[119] AEMO projections show that distributed storage capacity could reach almost 6 GW by 2030, equivalent to more than double the capacity of the Snowy 2.0 project.[120] Without reforms, up to 4 GW of this capacity may be price-responsive, but not participating in dispatch or visible to the market.[121]

The increasing prevalence of PRR has the potential to materially influence market outcomes. Very large industrial loads, such as aluminium smelters, can materially impact system demand at any given time. Similarly, large portfolios of batteries or aggregations of CER through VPPs can rival the size of centralised power plants and shift supply and demand dynamics to the same extent, significantly affecting demand forecasting and outcomes. Previously, simple demand response behaviours from large loads could be observed over time, but the increasing sophistication in demand response technologies, including of VPPs, is making price response more dynamic.

The Panel studied the various methods for participating in the NEM's wholesale and demand response markets. These include mechanisms provided in the regulatory framework, such as the WDRM and reforms under the IPRR rule, as well as avenues available to consumers through retailers. The Panel then identified the various methods as 'modes' of participation, with most demand response currently invisible to AEMO.

119 IEEFA (2025), Submission to the initial NEM Review consultation, p 9, 11.
120 AEMO (2025), 2025 Inputs and Assumptions Workbook.
121 Ibid.

The IPRR rule change allows demand side resources to participate in central dispatch

In December 2024 the AEMC published the IPRR final rule establishing a framework that enables aggregated CER to voluntarily participate in central dispatch. Under the new 'dispatch mode', small and medium-sized PRR can be aggregated and scheduled, allowing them to compete in the wholesale market alongside large-scale generation and storage assets.

Dispatch mode allows participants to operate in different states: dispatch mode (active), dispatch mode (inactive) or dispatch mode (hibernate). These mechanisms offer flexibility for participants to manage operational needs while supporting the broader integration of CER into the NEM.

- In **dispatch mode (active)** a participant submits bids for generation and load, receives dispatch targets, and follows dispatch instructions issued by AEMO. The active participation directly influences price signals and spot price formation because bids are incorporated into NEM central dispatch. By competing alongside scheduled generators and storage, participants can set marginal prices and respond dynamically to market conditions, improving efficiency and transparency in price formation.
- In **dispatch mode (inactive)** participants are removed from dispatch obligations but they must continue submitting bids and providing real-time operational data to AEMO. Their bids remain visible in the market, preserving some influence on price signals. This design ensures that resources can re-enter dispatch mode quickly without losing market visibility, but their impact on actual dispatch outcomes and price setting is limited compared to 'active' participation.
- A **dispatch mode (hibernate)** allows participants to be temporarily removed from dispatch obligations, bidding and real-time data provision.

Dispatch mode is due to commence in 2027 with an incentive framework due to commence in April 2026. AEMO published VSR Guidelines in November 2025 and the AER will initiate a consultation process for updates to its Rebidding and Technical Parameters Guideline (as required under the IPRR rule change).

Figure 36 categorises resources by how active and visible they are in the market and their level of responsiveness. Passive resources are unscheduled and uncontrollable, while participative resources are controlled and participate in dispatch, contributing to price formation. The Panel has identified a 'visibility gap' in the current market design: there is no mechanism to provide valuable information on price-responsive loads to the market operator where benefits of visibility outweigh the costs of information provision.

Figure 36 – Resource categories

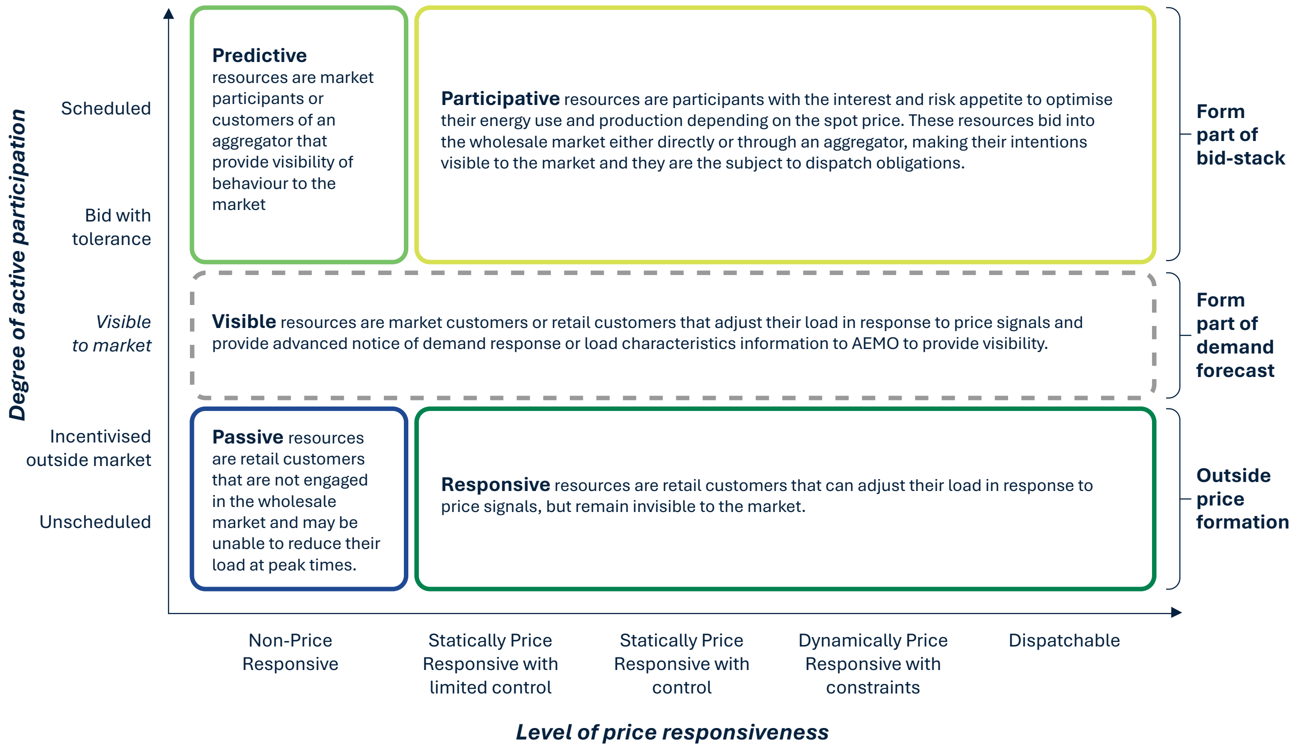
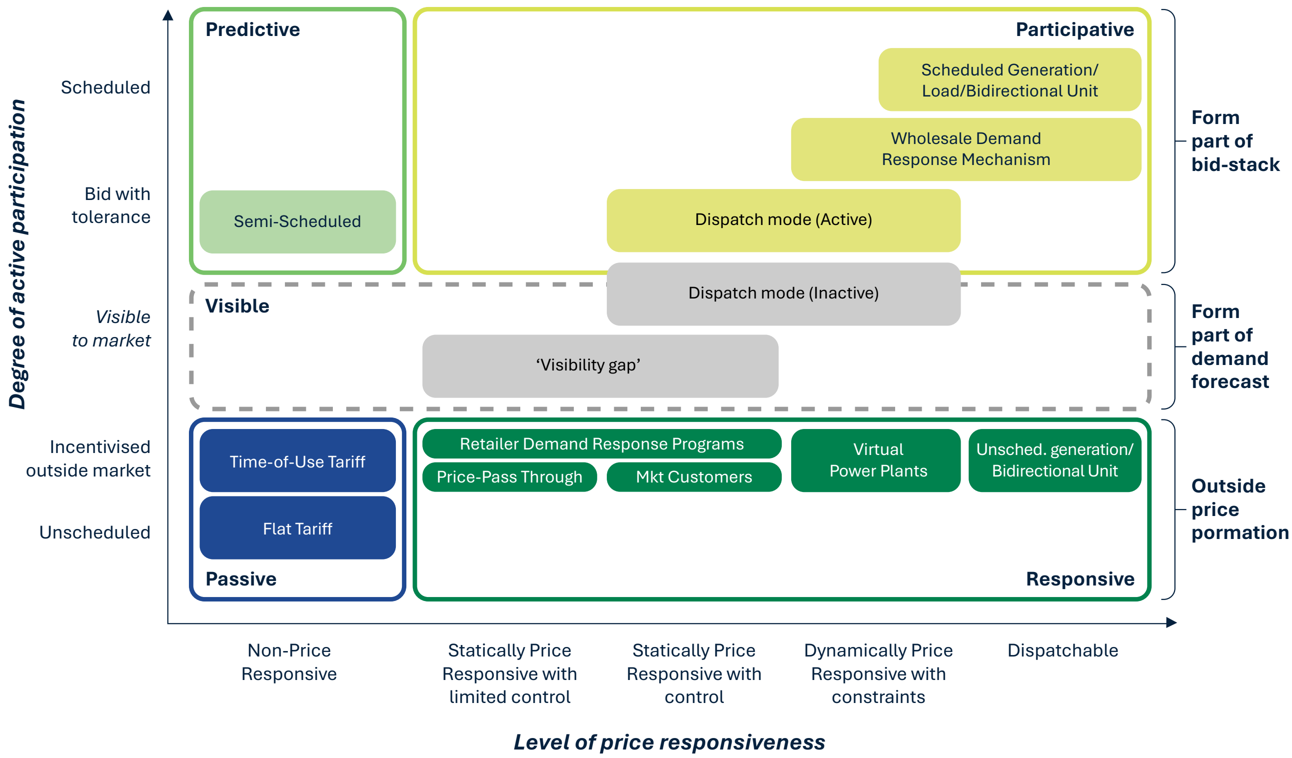


Figure 37 – Examples of predictive, participative, visible, passive and responsive resources



3.14 Enabling price-responsive resources to be visible or participate in dispatch would unlock competition and deliver savings for consumers

Enabling hidden price-responsive resources to become visible or participate in dispatch can address some of the current challenges by improving forecasts, reducing system costs (e.g. FCAS resulting from inaccurate forecasts), improving overall investment signals and, ultimately, putting downward pressure on wholesale prices.

AEMO and the AEMC have provided several estimates of the benefits from CER, DER and demand response:

- AEMO's 2024 ISP found that around $4.1 billion of additional grid-scale investment will be needed to 2050 without effective coordination of consumer batteries, increasing the costs that are reflected in consumer bills.[122]
- Intelligent Energy Systems (IES) modelling commissioned by the AEMC for the IPRR rule change found that the social benefit of visibility and dispatch of PRR could be between $1.4 and $1.8 billion, against a base case with no visibility of these resources. This represents a reduction in costs from lower regulation FCAS enablement volumes, emissions, generation costs needed to meet demand, and RERT costs.[123] IES modelling for the AEMC also found that the IPRR reform is expected to lower spot prices by between $12 billion and $13 billion (2023 dollars) and reduce FCAS prices between $678 million and $814 million.[124]

The Panel considers that broader involvement of flexible PRR in visibility and dispatch frameworks would deliver significant system-wide benefits. Ensuring these resources are visible or participate in dispatch would enhance market efficiency and operational resilience. Key benefits include:

- **Improved forecasting and dispatch efficiency:** Enhanced visibility enables AEMO to better anticipate demand fluctuations, reducing the risk of over- or under-commitment of generation resources.
- **Reduced price volatility:** Greater demand-side responsiveness mitigates scarcity events and extreme price outcomes, contributing to lower wholesale prices for all consumers.
- **Lower reliability intervention costs:** Greater visibility and access to flexible loads will ensure more system resilience and therefore reduce reliance on RERT and other high-cost interventions.
- **Enhanced renewable integration:** Dispatchable demand helps smooth variability in solar and wind generation, supporting a more stable and reliable renewable energy mix.

These benefits represent public-good outcomes that accrue to all consumers, including those who do not directly participate in demand-side programs.

[122] AEMO (2024), 2024 Integrated System Plan for the NEM, p 17.
[123] All figures in NPV 2023 dollars. IES (2024), Benefit analysis of improved integration of unscheduled price responsive resources into the NEM (ERC0352), p 7–9.
[124] Op Cit, p 13–15.

Recommendation 2A: Energy ministers should implement a mandatory framework for PRR visibility and participation in dispatch

Ministers should give effect to this by:

i) Tasking AEMO, in consultation with industry and consumer representatives, to develop by December 2026 a framework that: defines fit-for-purpose visibility modes and their adoption into operational forecasting; establishes thresholds for mandatory participation; and provides advice on consumer benefits and implementation pathways.

ii) Progressing amendments to the National Electricity Law (NEL) and National Electricity Rules (NER) to enable full implementation of the framework by 2030.

Through its investigation and engagement with stakeholders, the Panel has developed the following parameters and initial thresholds (within IPRR zones[125]) which should inform the development of the framework:[126]

- **Portfolio aggregations of small-scale storage** (without co-located load) that in aggregate exceed the NER's bidirectional unit (BDU) registration threshold (>5 MW) should be required to participate in dispatch mode (active) or as a BDU.
- **CER portfolio aggregations** with remote automated control and an aggregated capacity exceeding the NER's scheduled generation registration threshold (>30 MW), should be required to participate in dispatch mode (inactive), with dispatch mode (active) remaining voluntary. Aggregations below this threshold should provide quarterly reporting to AEMO identifying loads subject to such arrangements.
- **Large industrial and commercial loads** with aggregated capacity of price-responsive load across their portfolio that exceeds the NER's scheduled generation registration threshold (>30 MW), including those operating under price-contingent demand response contracts, should be required to provide load-intention data to AEMO via a dedicated visibility-only difference-bid mode or, alternatively, participate through the WDRM.[127]
- **Retailers offering pool-price pass-through arrangements or price-contingent demand response contracts**, where the aggregated capacity of price-responsive load is below the scheduled generation registration threshold (<30 MW), should be required to submit quarterly reports to AEMO identifying all loads subject to these contractual arrangements.[128]

This graduated approach recognises the diversity of demand-side resources and aligns obligations with controllability and system impact. It ensures that AEMO's situational awareness is enhanced, inefficiencies are reduced, and system-wide reliability and efficiency benefits are delivered, without imposing unnecessary cost or complexity on participants.

[125] Geographical zones defined by AEMO in the Voluntary Scheduled Resources Guidelines (released 27 November 2025). Review of zones will be considered in AEMO's review of VSR Guidelines that must occur by 1 May 2030.

[126] The Panel has refined this recommendation since the Draft Report through submissions, extensive engagement with a variety of PRR participants and collaboration with a broad range of stakeholders.

[127] To be clear, the Panel is not recommending that large electricity users be required to participate in dispatch. Rather, the Panel is recommending that the PRR component of a large electricity users load be visible to the market.

[128] This could build on the existing requirement to provide information through the demand-side participation information (DSPI) portal and would be used to improve operational forecasting rather than just for planning purposes such as the Electricity Statement of Opportunities (ESOO).

3.15 A mandatory framework for visibility and participation in dispatch is required

While the IPRR rule change in December 2024 established a framework for voluntary participation in dispatch mode, the Panel remains concerned that this opt-in approach will not deliver the necessary uptake and visibility. This is particularly relevant considering the rapid deployment of battery storage systems across the NEM.

The Panel considers that only a mandatory framework that obligates the visibility or participation of PRR participants in dispatch (when over a certain size) will address the emerging challenges to market efficiency and operational performance. The AEMC acknowledged this issue in its final determination on IPRR, noting that "the majority of unscheduled price-responsive resources are unlikely to participate in dispatch mode in the near term, and potentially into the future."[129] The AEMC also identified merit in mandating participation for large loads, mid-sized generators (1–30 MW) and storage systems (1–5 MW).[130]

To support future decision-making the AEMC's IPRR monitoring and reporting framework will provide transparency on the extent to which AEMO's forecasting errors are attributable to unscheduled PRR. This will enable energy ministers to assess the materiality of associated costs and determine whether implementation of a mandatory framework should be brought forward ahead of 2030.

Stakeholder feedback on mandating visibility or participation in dispatch of PRR

Several stakeholders raised concerns with mandating PRR inclusion in central dispatch and questioned the materiality of AEMO's forecasting error attributed to unscheduled PRR.[131] In response, the Panel has refined its recommendation to only recommend that those PRR capable of participating in dispatch be required to do so, with the majority of PRR (when above a certain size threshold) to provide visibility to the market operator.

A range of stakeholders, including AEMO, ARENA, and the Smart Energy Council, expressed support for a phased approach to implementing a mandatory framework, ensuring that resources are not disincentivised from innovating and investing in the near term.[132] The Panel agrees with this feedback and has sought to design an approach that strikes the right balance between giving industry enough time to prepare and responding to the urgency of the issue. The recent pace and scale of battery installations observed in the NEM is such that the Panel considers that immediate action to develop the mandatory framework is warranted, to ensure it is ready when necessary, by 2030.

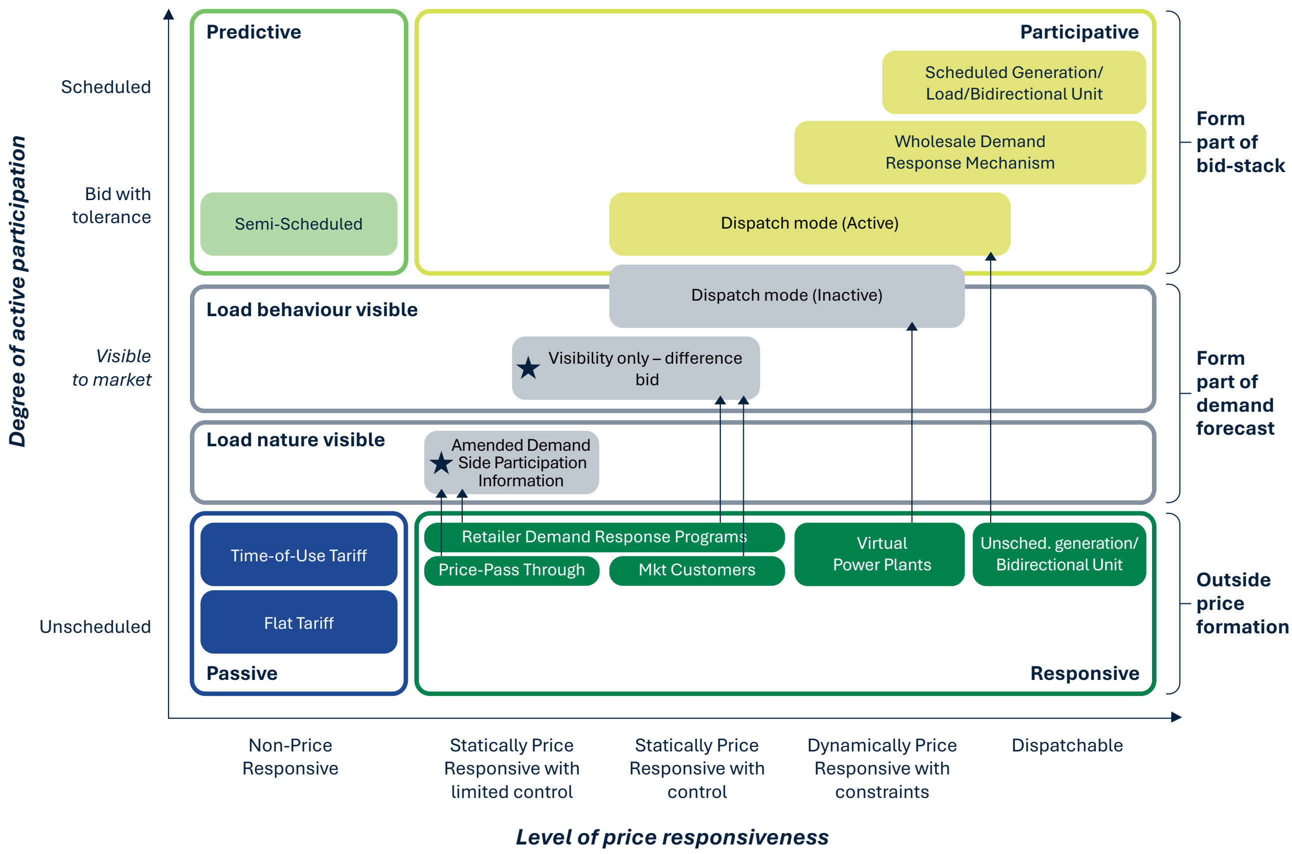
[129] AEMC (2024), Integrating price-responsive resources into the NEM final determination, p 25.
[130] Op Cit., p 27.
[131] Submissions to the NEM Review Draft Report consultation from AEMC (p 2), AEMO (p 3), AFMA (p 10), AGL (p 5), Alinta (p 9), Aluminium Council (p 3), ARENA (p 3), BlueScope (p 3), CEIG (p 5), CS Energy (p 4), EDF (p 10), EnergyAustralia (p 5), EUAA (p 4), Flow Power (p 4), Nexa Advisory (p 6), Origin Energy (p 4) and Tilt Renewables (p 5).
[132] Submissions to the NEM Review Draft Report consultation from AEMO (p 1), ARENA (p 5) and Smart Energy Council (p 4).

3.16 Visibility and participation modes should match resource capabilities

While the Panel recommends that visibility and dispatch modes should be mandatory for certain PRR, the mode of participation and associated obligations should be driven by the resource capability and its operational impact on dispatch outcomes.

Figure 38 illustrates the Panel's intent to enhance market visibility and participation in dispatch of PRR. By establishing differentiated modes that reflect varying levels of price-responsiveness and controllability, including a proposed new visibility-only mode, the framework ensures that resources are not required to exceed their market participation capabilities. At the same time, it facilitates improved operational efficiency and market outcomes through enhanced visibility of these resources. This provides a model on which a more comprehensive mandatory framework for PRR visibility and participation can be developed.

Figure 38 – The Panel's recommendations intend to move hidden PRR into visible and participative modes



In the Draft Report, the Panel proposed that all PRR should be either visible or dispatchable within an appropriate existing participant category (through the IPRR rule change). Subsequent stakeholder engagement revealed that the predictability and responsiveness of different resource types constrain their ability to participate under current market frameworks.

Resources with high levels of control and the ability to respond accurately and frequently to price signals, such as large-scale batteries, are considered dynamically responsive and are generally capable of participating through existing mechanisms. In contrast, certain loads only respond to price when spot prices exceed a defined threshold and operational conditions permit a reduction in consumption. These resources are classed as statically price-responsive. Stakeholder feedback indicates that such loads are typically less predictable and possess limited controllability, making them unsuitable for participation under existing frameworks. Retailers with CER aggregations have indicated that due to a variety of business models and contractual arrangements, these loads have varying levels of responsiveness with some able to dynamically respond to price with remote automated control and others with limited influence where the customer retains control.

The Panel considers that the requirements of the existing participation modes available in the market (IPRR, WDRM, scheduled load and bidirectional unit) are not sufficiently flexible to cater to the full spectrum of PRR capabilities. These mechanisms were designed for specific resources and operational contexts.

- IPRR is suited to participants that are dynamically responsive, capable of providing accurate 5-minute load forecasts and remote control enabled demand response. This is not well aligned with statically responsive loads or resources that lack real-time telemetry.
- WDRM is designed for large market loads or energy consumers with a predictable demand profile to bid demand response into the market. However, WDRM's reliance on baseline methodologies to quantify dispatched response makes it unsuitable to flexible, aggregated or dynamic CER portfolios.
- While direct dispatch participation for large loads (via registration as scheduled loads or bidirectional units) provides the highest level of dispatchability and visibility to the market, stakeholders have highlighted that participation would impose material compliance costs, distract from core business operations, and impose high regulatory obligations disproportionate to the role and risk of large loads in the market.

The Panel has identified a structural gap in the current market design: there is no fit-for-purpose mode for statically responsive resources to provide valuable information to the market operator. To address this, the Panel considers that a targeted visibility-only mode is required. This mode would enable the system operator to receive advance notice of expected demand reductions without imposing five-minute forecasting or dispatch obligations. In parallel, AEMO could enhance visibility of smaller aggregations of PRR through its existing information-gathering powers, for example through increased frequency and accuracy of reporting via the Demand Side Participation Information (DSPI) Portal. This could be used to improve operational forecasting rather than just for planning purposes such as the Electricity Statement of Opportunities (ESOO).

In response to these findings and stakeholder feedback, the Panel has refined its recommendation to support the development of tailored visibility modes that align with the operational characteristics of different resource types. These refinements reflect further analysis and stakeholder input on the trade-offs between improved market efficiency through enhanced visibility and the need to maintain flexibility to support ongoing innovation in demand-side participation.

The Panel supports a tiered visibility approach that:

- Recognises diversity in business models, operating cycles and flexibility
- Avoids imposing obligations that could undermine innovation
- Enables AEMO to access relevant operational data (e.g., typical demand profiles, expected curtailment capacity) without imposing real-time participation requirements
- Focuses on achieving practical improvements in market transparency and forecasting accuracy.

To be clear, the Panel is recommending a framework that does not require participants to go beyond the mode of participation that best suits their capability. Where PRRs are technically capable, they may choose to voluntarily participate in more active modes to unlock benefits of increased participation. This approach seeks to accommodate the diversity of PRR without constraining investment and innovation.

Stakeholder feedback on existing modes for demand response

While stakeholders broadly supported the principle of improving visibility of PRR, stakeholders did not support a blanket mandate on participation in dispatch utilising existing modes for all resources.[133] This included highlighting:

- **Costs:** Stakeholders considered that mandating dispatchability would impose disproportionate costs on certain participant types, such as large loads that are not always price-responsive.[134] Stakeholders noted that compliance with the proposed IPRR rules would require significant investment in telemetry, control systems and metering infrastructure including SCADA, which may outweigh demand response benefits.[135]
- **Limitations of IPRR dispatch mode:** Some stakeholders cautioned the use of IPPR active or inactive mode for all aggregations of CER, noting in many cases customers retain control of resources.[136] Some noted a lack of clarity around the ongoing development of IPRR rules including whether the framework supports long term inactive users. Stakeholders noted further development and refinement of the IPRR framework is needed.[137]
- **Specific participation solutions:** Stakeholders identified the risk that locking in particular solutions for participation could stifle innovation.[138]

The Panel has considered this feedback and understands the costs and risks associated with mandating dispatch participation via mechanisms that were not designed for all resource capabilities. The Panel has therefore updated its final recommendation to focus on the development of a fit-for-purpose framework with modes matched to a resource's capability.

3.17 Energy ministers should task AEMO to develop a fit-for-purpose framework

The Panel proposes that AEMO be tasked to develop a framework that defines fit-for-purpose visibility modes and their adoption into operational forecasting, establishes thresholds for mandatory participation, and provides advice on consumer benefits and implementation pathways. Importantly, this should include directing AEMO to collaborate closely with industry stakeholders and consumer representatives to develop fit-for-purpose visibility modes and participation thresholds.

[133] Submissions to the NEM Review Draft Report consultation include Origin (p 4), AGL (p 5), Flow Power (p 4), Nexa Advisory (p 6), ARENA (p 3), EDF (p 10), AEMC (p 2), AFMA (p 10), CEIG (p 5), CS Energy (p 4), Aluminium Council (p 2), Alinta (p 9), Tilt Renewables (p 5), EUAA (p 4), EnergyAustralia (p 5), BlueScope (p 5) and AEMO (p 3).
[134] Submissions to the NEM Review Draft Report consultation include Aluminium Council (p 2) and BlueScope (p 5).
[135] Submissions to the NEM Review Draft Report consultation include BlueScope (p 8), Flow Power (p 4) and Origin Energy (p 6).
[136] Submissions to the NEM Review Draft Report consultation include Flow Power (p 6) and BlueScope (p 7).
[137] Submissions to the NEM Review Draft Report consultation include AEC (p 6), Flow Power (p 7), Enel X (p 5) and Ergon Energy and Energex (p 2).
[138] Submissions to the NEM Review Draft Report consultation include ARENA (p 3) and Community Power Agency (p 4).

Visibility and participation modes should enable resources to engage in market processes in a manner consistent with their technical and operational capabilities. The Panel also recommends that AEMO be required to regularly publish how the new information being provided is improving its operational forecasting and benefiting consumers. The Panel considers AEMO's Forecasting Reference Group (FRG)[139] could provide support in defining how new information is adopted into operational forecasting.

Further, AEMO could consider an exemption from the mandatory framework for unique sites where it may be impractical to forecast load behaviour in line with mode requirements.

3.18 Thresholds for participation should be principles-based and continue to evolve with the market

Thresholds should be reviewed and adjusted as market uptake, technology and operational experience mature. As such, the thresholds for participation should be principles-based and aligned with the evolving capability of PRR and AEMO's systems to utilise visible and operational data effectively.

Table 1 provides the principles the Panel recommends for guiding the establishment of PRR thresholds and modes. These principles have been informed by stakeholder feedback.

Table 1 – Principles guiding establishment and adjustment of PRR thresholds and modes

Improve wholesale price and system outcomes	• Thresholds should capture individual sites, aggregations and/or market shares that are large enough to materially reduce forecasting error and improve pricing efficiency.
Reflect a resource's ability to respond to price	• Thresholds and modes of mandated visibilityand participation in dispatch should be tailored for dynamically price-responsive, statically price-responsive, or not price-responsive CER and demand response (DR) resources.
Provide consistency across resource types	• Alignment with current thresholds in the NER. • Substitutable resources subject to same obligations (address risk of regulatory arbitrage).
Minimise the cost of participation and maximise system benefits of CER and demand response	• Minimise upfront and ongoing administrative and compliance costs. • Optimise thresholds to minimise risk that mandating above certain thresholds disincentivises price-responsiveness. • Retain focus on practical implementation strategies to reduce implementation costs.

To ensure consistent visibility and efficient integration into AEMO's operational forecasting processes, the Panel recommends that specific PRR participant groups be required to participate in capability matched modes based on their operational characteristics (and where their capacity exceeds defined minimum thresholds).

Through its investigation and engagement with industry on this recommendation, the Panel has developed parameters and initial thresholds (within IPRR zones[140]) which should inform the

[139] The FRG is an open forum comprised of forecasting specialists that facilitates discussion and shares insights and outcomes of forecasting approaches used in AEMO publications.

[140] Geographical zones defined by AEMO in the Voluntary Scheduled Resources Guidelines (released 27 November 2025). Review of zones will be considered in AEMO's review of VSR Guidelines that must occur by 1 May 2030.

development of the framework by AEMO, as summarised in Table 2. The recommended reforms for the main types of PRR are discussed below.

Table 2 – PRR parameters and initial thresholds

Category	Definition	Characteristics	Participation requirement
1. Portfolio aggregations of small-scale storage	Portfolio aggregations of small-scale storage (without co-located load) that in aggregate exceed the NER's BDU registration threshold (>5 MW).	Dynamically price-responsive, capable of providing accurate 5-minute load forecasts and remote control enabled demand response.	Must either: • Participate in dispatch mode (active); or • Participate as bidirectional units.
2. CER portfolio aggregations	CER portfolio aggregations with remote automated control and an aggregated capacity exceeding the NER's scheduled generation registration threshold (>30 MW).	Dynamically price-responsive, capable of providing reasonably accurate 5-minute forecasts.	Must participate in dispatch mode (inactive). Aggregations below the threshold must provide regular information to AEMO identifying all loads subject to such arrangements.
3. Large industrial and commercial loads	Large industrial and commercial loads with aggregated capacity of price-responsive load across their portfolio that exceeds the NER's scheduled generation registration threshold (>30 MW), including those operating under price-contingent demand response contracts.	Generally statically responsive, facing barriers to participating in central dispatch or meeting compliance obligations of available mechanisms.	Must either: • Provide load-intention data to AEMO via a dedicated visibility-only difference-bid mode; or • Participate through the WDRM.
4. Retailer-linked small loads	Retailers offering pool-price pass-through arrangements or price-contingent demand response contracts, where the aggregated capacity of price-responsive load is below the scheduled generation registration threshold (<30 MW).	Varied ability to respond to price, not well suited to meet dispatch and compliance obligations of available mechanisms.	Must provide regular information to AEMO identifying all loads subject to such arrangements.

1. Recommended reform for aggregations of small-scale distribution-level storage without co-located load

Portfolio aggregations of small-scale storage (without co-located load) that in aggregate exceed the NER's BDU registration threshold (>5 MW) should be required to participate in dispatch mode (active) or as a BDU.

The Panel's recommendations build upon the foundational work undertaken by market bodies in developing the IPRR framework, scheduled for commencement in May 2027. Dispatch mode (active) is a mechanism to facilitate broader participation of PRR in the spot market.

Individual batteries above 5 MW are required to participate in dispatch as bidirectional units, but batteries below this threshold are not, leading to potential aggregated portfolios of sub-5 MW effectively becoming hidden participants. The Panel considers these portfolios should be required to participate in dispatch mode (active) once the aggregate size exceeds 5 MW. The same requirement would apply to portfolios of small generation units. This recommendation has not changed since the Draft Report.

Dispatch mode (active) enables eligible resources to submit bids, set prices, receive dispatch instructions and access FCAS revenue streams. It has been designed to accommodate the operational characteristics of smaller-scale and aggregated DER, reducing barriers to entry while maintaining the necessary visibility for AEMO to forecast, plan and operate the power system effectively.

The Panel considers that dispatch mode (active) achieves an appropriate balance between operational transparency and participant flexibility for these resource types. Importantly, participants operating in dispatch mode are exempt from cost recovery obligations associated with RERT and directions, and are eligible to receive Frequency Performance Payments.

Stakeholder feedback on portfolios of small batteries

Stakeholder feedback identified battery energy storage systems as resources capable of meeting the IPRR dispatch mode (active) compliance requirements and agreed that rules for portfolios of batteries with aggregated capacity above 5 MW should mirror the existing requirements for individual batteries above 5 MW.[141] The Panel has maintained and refined its position that aggregations of small batteries without co-located load should be required to participate in dispatch mode (active) or as bidirectional units.

[141] Submissions to NEM Review Draft Report consultation including Rainbow Power (p 3), EDF (p 10), SA Power Networks (p 3) and Ergon and Energex (p 2). Feedback was also received in direct discussions with stakeholders.

2. Recommended reform for large aggregations of CER

CER portfolio aggregations with remote automated control and an aggregated capacity exceeding the NER's scheduled generation registration threshold (>30 MW), should be required to participate in dispatch mode (inactive), with dispatch mode (active) remaining voluntary.

Retailers with CER load aggregations that have remote automated control should be required to forecast the behaviour of the entire aggregation at different price levels through dispatch mode (inactive). The Panel recommends a 30 MW combined capacity threshold that mirrors the existing requirement for scheduled generators as an appropriate starting threshold which could be reduced over time, as needed. The proposed IPRR zones may mean this threshold is set too high to capture the visibility needed and the threshold should be reviewed by AEMO at regular intervals.

To be clear, the Panel's recommendation for visibility does not apply to 'passive' CER and is not proposing that households with batteries be required to join a VPP. Where households choose to participate, they are not required to participate individually in visibility modes or directly enter the energy-only spot market. Instead, the focus is on aggregators. This approach aligns with the intent of the IPRR and ensures that households can benefit from market participation without the complexity of direct involvement.

Through engagement with the Panel, AEMO has expressed concern that forecasts submitted without associated conformance obligations may not be sufficiently reliable for operational purposes. To address this, the Panel recommends that AEMO publish regular performance data on the accuracy of retailer-submitted forecasts. This transparency is expected to encourage a best endeavours approach to forecast accuracy and support continuous improvement.

AEMO has indicated that, over time, enhanced visibility of retailer-level load behaviour will provide certainty over how 'firm' the load is, and iterative refinement of AEMO's forecasting algorithms will enable greater confidence in the use of inactive bids for operational decision-making. The Panel considers that engaging with industry specialists through the AEMO FRG could also support AEMO in effectively utilising this enhanced visibility data.

Stakeholder feedback on CER aggregations

Stakeholders expressed broad support for the visibility of CER aggregations, recognising the challenges of managing the growth in hidden price-responsive resources.[142] However, stakeholders were cautious about placing dispatch obligations on resources which are subject to a vast array of business models. Stakeholders also stated that conformance obligations should not disincentivise demand response participation.[143] The Panel has updated its recommendation to focus on visibility and mandate participation in dispatch mode (inactive) only. The updated recommendation also explicitly refers to CER aggregations with 'remote automated control' to distinguish between the different types of contractual arrangements and target only those resources that are capable of meeting the requirements of the mode. Other types of resources are addressed through the recommendations on price pass-through and retailer contracts.

[142] Submissions to the NEM Review Draft Report consultation include CleanCo (p 2), ARENA (p 3), Tesla (p 2), Clean Energy Council (p 2), Cau Thai (p 4), Energy Networks Australia (p 3) and Electrical Trades Union (p 18).
[143] Submissions to the NEM Review Draft Report consultation include Smart Energy Council (p 2), Rainbow Power Company (p 6), EDF (p 8), Alinta (p 8), EnergyAustralia (p 5), Enel X (p 17), Tesla (p 4), Community Power Agency (p 4), CEC (p 14) and Cau Thai (p 13).

3. Recommended reform for large price-responsive loads

Large C&I users with aggregated capacity of price-responsive load across their portfolio that exceeds the NER's scheduled generation registration threshold (>30 MW), including those operating under price-contingent demand response contracts, should be required to provide load-intention data to AEMO via a dedicated visibility-only difference-bid mode or, alternatively, participate through the WDRM.

Large loads are, in many cases, already demand-responsive, and companies manage their exposure to volatile spot prices with firm operational guidelines and a relatively higher level of sophistication than smaller loads. However, without visibility of load intentions, there have been instances where AEMO has intervened to meet forecast demand and subsequently found it was unnecessary due to a significant drop in industrial load, increasing costs for consumers.

The Panel has identified large load resources as being largely statically responsive. These loads face many barriers to participating in central dispatch (discussed above in **C&I Demand Flexibility**) and are not designed to operate as generators or to provide continuous, real-time balancing services to the market operator. A mandate must therefore recognise these operational limitations and ensure that obligations placed on C&I users are proportionate, practical and risk appropriate. The Panel is not recommending large energy consumers be required to participate in dispatch, but is instead recommending that the price-responsive component of large loads be made visible to the market. The Panel does not consider the visibility framework as a step towards mandatory participation in central dispatch.

The Panel has engaged with AEMO to explore the development of a visibility-only mode tailored to statically responsive resources. This mode would not require continuous interval-level forecasting or dispatch conformance. Instead, it would provide AEMO with timely notification of demand response events, enabling improved operational awareness and forecasting accuracy without imposing dispatch obligations.

Through these discussions, the Panel and AEMO identified that a difference bid-type approach (whereby the participant identifies how much their load will change in response to different price outcomes) may be appropriate. This could mirror the WDRM framework, which requires participants to submit bids reflecting the change in load demand rather than full-load forecasts. Such an approach would reduce administrative burden while improving visibility to support efficient dispatch and system operation.

Stakeholder feedback on large loads

In its Draft Report, the Panel proposed that large loads should actively participate in dispatch mode via WDRM, or as scheduled loads. However, stakeholder feedback indicated that the requirement to submit five-minute interval forecasts and associated dispatch conformance obligations under dispatch mode presents significant challenges and disproportionate costs on large energy consumers.[144] The Panel's final recommendation has been updated to mandate that by 2030 a tailored visibility-only requirement be introduced to ensure that obligations placed on large users are proportionate, practical and risk appropriate.

[144] Submissions to the NEM Review Draft Report consultation include EUAA (p 4), BlueScope (p 5), Aluminium Council (p 2) and the Energy Efficiency Council (p 13). Feedback was also received in direct discussions with stakeholders.

4. Recommended reform for price-responsive retail contracts

Retailers offering pool-price pass-through arrangements or price-contingent demand response contracts, where the aggregated capacity of price-responsive load is below the scheduled generation registration threshold (<30 MW), should be required to submit quarterly reports to AEMO identifying all loads subject to these contractual arrangements.

Pool-price pass-through and price-contingent demand response contracts play an important role in enabling consumers to elect to manage their exposure to wholesale prices. Consumers can vary their consumption in response to spot prices, either directly through cost pass-through or indirectly through pre-agreed price triggers. While these contracts encourage more responsive demand, AEMO has limited visibility of these customers and their potential response to forecast price changes.

The recommended provision of regular information recognises the diversity of demand response in the market, including that the ability for demand response to respond to price is varied, often over-estimated and not always suitable for dispatch and compliance obligations. Instead, improved discovery of loads on price-responsive contracts will help identify PRR in the market and enable AEMO to improve forecasting models of operational demand.

The Panel also recommends this requirement should apply to aggregations of CER below the proposed 30 MW threshold. The Panel considers this increased visibility is an efficient and proportionate means of incorporating the influence of smaller aggregations of CER on price dispatch outcomes.

In development of this recommendation, the Panel worked with AEMO to understand the type and form of information that could be used to inform demand forecasting and improve dispatch efficiency. The Panel recommends AEMO defines an appropriate mechanism for collection of this information. For example, the existing DSPI portal could be enhanced to support quarterly data submissions. The Panel understands that alternative options may also be considered, including AEMO's Market Settlement and Transfer Solutions or the DER register.

Stakeholder feedback on price-responsive retail contracts

In the Draft Report, the Panel considered requiring retailers with portfolios of pool-price pass-through or price contingent demand response contracts to participate in IPRR dispatch mode (inactive or active). The Panel also flagged lighter-handed options focused on visibility only. Stakeholders were unsure of how to define customers on these contracts, citing the many varieties of contract types used, including those on a blend of fixed and variable pricing.[145] Retailers noted that many customers on these contracts were not price-responsive all the time or that the lack of control of these loads impeded their forecasting ability.[146]

In response to stakeholder feedback, the Panel recognises the ability for retailers offering pool-price pass-through contracts, or that have price contingent demand response contracts, to participate in dispatch mode (inactive) is impractical at this stage. The Panel's revised recommendation is focused on the provision of information at regular intervals which will improve operational forecasting over time.

[145] Submissions to NEM Review Draft Report consultation including Origin Energy (p 5) and Hydro Tasmania (p 17).
[146] Submissions to NEM Review Draft Report consultation including Sarea Coates (p 8), Origin Energy (p 5), Flow Power (p 6), BlueScope (p 8), Hydro Tasmania (p 5) and Enel X (p 7).

3.19 Energy ministers should progress amendments to the NEL and NER to enable implementation of a framework by 2030

Under the IPRR rule change, AEMO will deliver by October 2026 its first annual report evaluating the effect of PRR on the accuracy of AEMO's short-term demand forecasts and associated impacts on market efficiency.

Following this, it is envisaged that AEMO would present its proposed mandatory PRR framework to energy ministers in 2026, including advice on the consumer benefits of the framework, implementation pathways and recommended changes to the NER.

To ensure a framework can be implemented by 2030, it is recommended that as part of a NEM Review legislative package and in parallel to AEMO developing the mandatory framework, energy ministers progress the necessary amendments to the NEL to provide for a minister initial rule establishing the new PRR framework.

> Recommendation 2B: Energy ministers should establish a structured support framework to encourage currently non-scheduled PRR to participate in dispatch mode (active), the WDRM, or as scheduled loads, generators or bidirectional units

3.20 Targeted support is needed to unlock greater market participation of price-responsive resources

Stakeholder consultations, including structured interviews with C&I users, indicated that there are barriers to demand response resources actively participating in dispatch, including the:

- cost of initial investments needed to meet dispatchability requirements, such as telemetry
- cost of building up capability to participate in the wholesale market
- risks associated with participating in the wholesale market
- potential loss of value as participative demand response reduces wholesale spot prices.

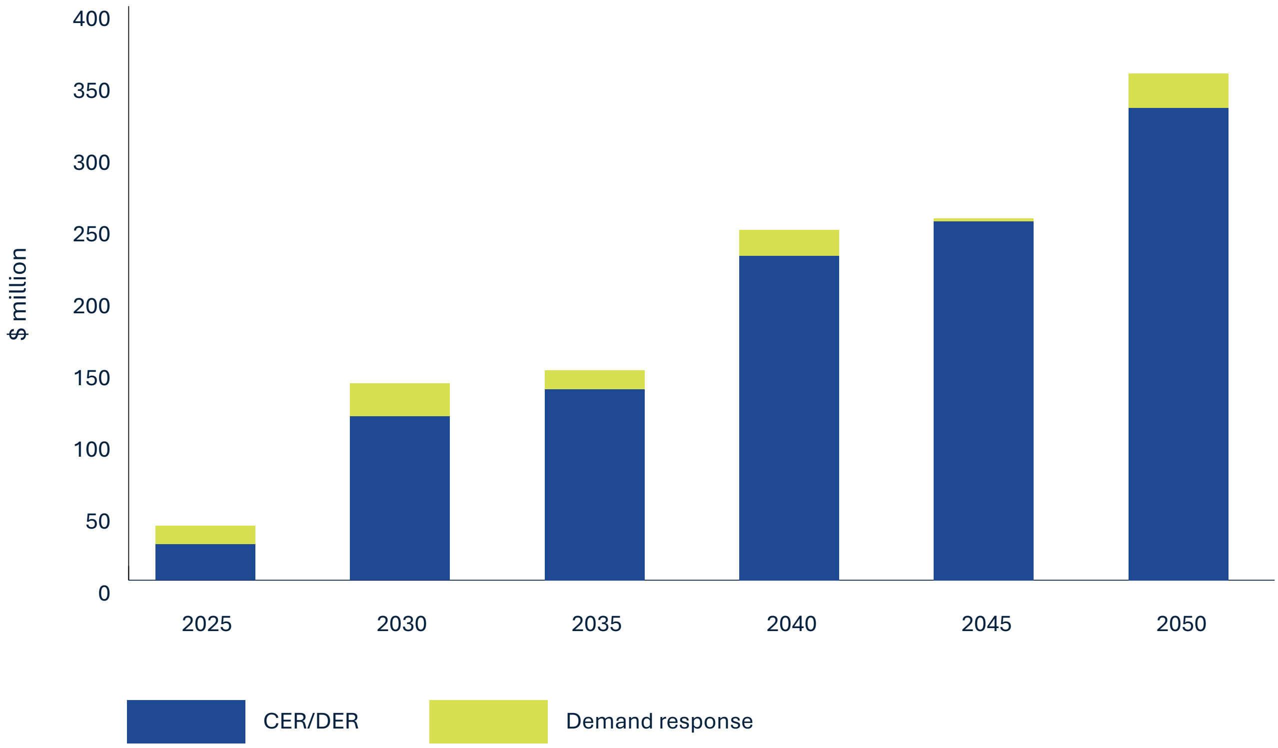
To lift participation in dispatch, the Panel recommends that any support for PRR must be meaningful enough to overcome the practical barriers that currently keep many of them 'hidden' from the wholesale market. At the same time, support should not exceed the value these resources add to the system. In other words, public funding should only go as far as ensuring that the system-wide benefits created by making a marginal PRR dispatchable exceed the costs.

In its 2024 IPRR rule determination, the AEMC concluded that an incentive mechanism is necessary to encourage voluntary participation in dispatch mode and that it would contribute to the National Electricity Objective (NEO) by lowering wholesale energy system costs for consumers. This mechanism drives participation by requiring AEMO to conduct tenders to pay participants to enter dispatch mode in the first five years of the mechanism.[147] The overall payments to IPRR participants

[147] AEMC (2024), National Electricity Amendment (Integrating price-responsive resources into the NEM) Rule 2024, final determination, p i.

are capped at $50 million and will be recovered by AEMO from market customers, primarily retailers and, ultimately, consumers.[148] Figure 39 shows the estimated economic benefits over time from integrating dispatchable PRR.[149]

Figure 39 – Estimated benefits of integrating price-responsive resources over time



Source: IES (2024), Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, p 18

3.21 Longer-term structured support may also be needed to encourage participation in dispatch

Ongoing structured support may be needed to support consumers to become participative in dispatch in the context of voluntarily shifting from visibility-only mode.

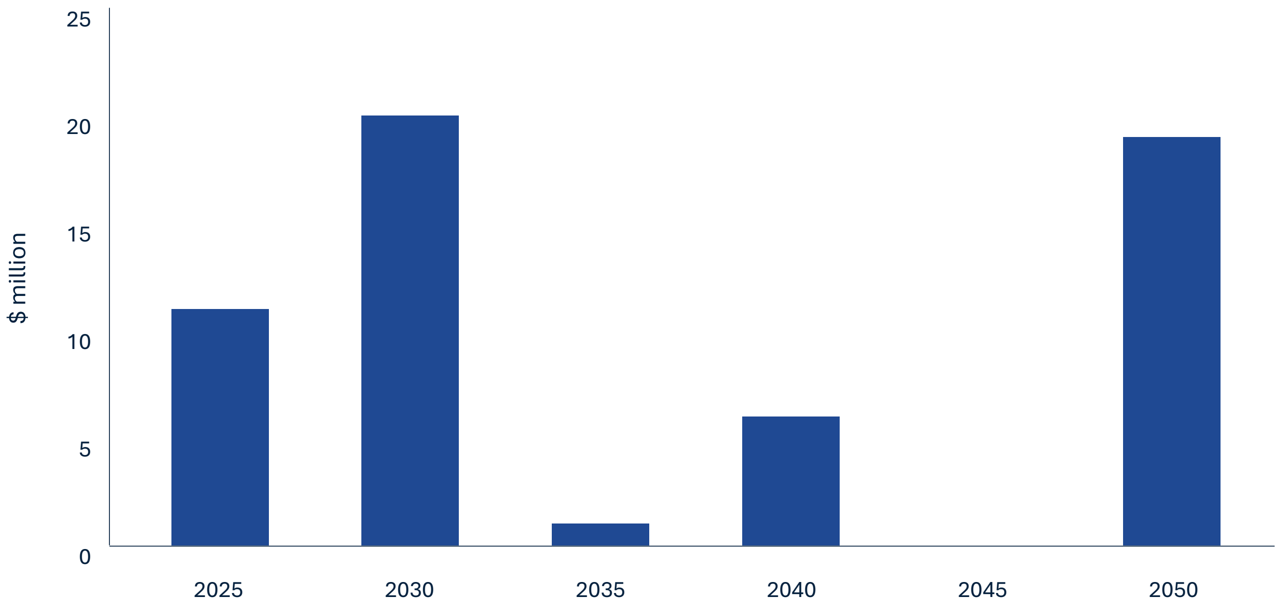
There is a range of options to support the cost of initial investments needed to provide price-responsiveness in a participative way. This could include increasing the total amount of incentives available under the IPRR incentive pool to better reflect the benefits provided and to create a longer-lasting mechanism to offer certainty for participants. Tender amounts could be tiered to reflect participation levels.

A second option could be a grant scheme for such investments, analogous to the typical market development funding managed by ARENA. Consideration could be given to an ARENA targeted funding round to support investment costs needed to facilitate participation in the market through the VSR framework (or another appropriate framework), building on the extensive work ARENA has already done to support market development in this area.

[148] AEMC (2024), National Electricity Amendment (Integrating price-responsive resources into the NEM) Rule 2024, final determination, p 41.
[149] IES (2024), Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, p 18.

For longer-term structured support, demand response could tender for an ESEM contract (see **Recommendation 10**). Existing funds intended to be tendered through AEMO could be offered through the ESEM to streamline the demand response support process. The Panel anticipates that the effective provision of electricity services (including by demand response providers) would reduce the reliance on RERT activation, thereby reducing associated costs for market participants. Figure 40 shows RERT cost-reduction estimates for probabilistic uptake of dispatch mode.

Figure 40 – Estimated benefits of reducing RERT costs



Source: IES (2024), [Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM](), p 13.

As the regulatory framework underpinning the NEM continues to evolve, there remains a range of long-term support mechanisms that are either not currently compatible with the existing market design or have yet to be trialled or modelled. These include, but are not limited to, approaches involving potential DOE prioritisation or exemptions for dispatched PRR. The Panel considers that further exploration of these and other alternative frameworks is warranted. Recent trials, including Project Edith, are expected to provide critical insights into potential scale-up feasibility and implementation pathways for DOEs in the NEM.[150]

To be clear, the Panel is not recommending ongoing unlimited funding be provided for incentivising dispatchability. This should only continue where the costs of such funding are more than offset by the benefits to consumers of lower overall wholesale energy costs (and network charges) from improving system utilisation and avoiding unnecessary over-investment. Market bodies should continuously assess this to determine the appropriate level of funding over time.

[150] Ausgrid (2023), Project Edith Knowledge Sharing Report.

3.22 Investment in new demand response resources would be eligible for shaping and firming services under the ESEM

The Panel recommends establishing an ESEM to address the mismatch in contracting tenors between buyers and sellers. Through consultation with end users, the Panel found this tenor gap also applies to demand response and flexible loads. Larger C&I users noted that longer-term revenue certainty is needed to justify investments in making their operations more flexible.

The proposed ESEM is designed to be technology-neutral and indifferent between large- and small-scale resources and supply and demand resources. New demand response resources would be therefore eligible to compete for financial derivative contracts offered under the ESEM shaping and firming services. These resources would be required to participate in the wholesale market, either in dispatch mode (active), through the WDRM, or as scheduled load. The design of the ESEM is discussed in **Chapter 5: Unlocking long-term investment in new energy services**.

Stakeholder feedback on PRR framework participation incentives

The Panel received feedback from several stakeholders regarding its recommendation for structured support frameworks. In addition, direct interviews were held with stakeholder representatives of the four PRR categories across **Recommendation 2A**'s mandatory framework.[151] Stakeholder feedback reflected broad support for targeted incentives to encourage PRR framework participation. Stakeholders highlighted specific incentive design considerations and placed differing value on the importance of targeted and longer-term structured support.

Some stakeholders recommended prioritising a mandated visibility framework ahead of finalising incentive structures.[152]

Stakeholders provided feedback on appropriate frameworks for targeted support, with some stakeholders noting the risks with using grant schemes include significant application and administrative costs.[153] Some stakeholders supported utilising the IPRR incentive mechanism.[154] Others suggested the focus for targeted support should be ensuring accountability for providing accurate and useful data.[155]

For longer-term support, stakeholders broadly agreed with the need for structured support but provided differing views on the mechanism.

The ESEM was raised as a possible option for incentives for PRR participation, if appropriately designed.[156] Some stakeholders noted untested options for structured support such as network constraint exemptions or priority dispatch which may provide benefit in the longer term.[157]

[151] Interview consultations with Tesla, Enel X, MTA Energy, AGL, Amber, Flow Power, Origin Energy, Rio Tinto, Alcoa, EUAA and Reposit on Recommendation 2.
[152] Submissions to the NEM Review Draft Report consultation from AEMO (p 4) and Origin Energy (p 6).
[153] Interview consultation with a retailer on Recommendation 2.
[154] Submissions to the NEM Review Draft Report consultation from Tesla (p 3) and Origin (p 6).
[155] AEMO (2025), submission to the NEM Review Draft Report consultation, p 4.
[156] EnergyAustralia (2025) submission to the NEM Review draft report consultation, p 6.
[157] Interview consultation with a retailer on Recommendation 2.

Stakeholders agree that the chosen support framework must be commercially and operationally sound. Feedback emphasised that incentive design should overcome barriers while ensuring business models remain financially viable for participants.[158]

The Panel has considered this feedback and has retained its draft recommendation for a targeted and structured support framework. The Panel has retained its recommendation for a short-term structured support framework that involves utilising the IPRR incentive mechanism or a grant-style fund and has refrained from recommending a specific mechanism to provide long-term structured support.

158 Submissions to the NEM Review Draft Report consultation from Aluminium Council (p 2), Nexa Advisory (p 6) and interview consultation with a retailer on Recommendation 2.

Recommendation 3: Governments should focus reforms and support for CER on facilitating market participation to enable consumers to benefit from being price-responsive

Recommendation 3A: Energy ministers should focus the National CER Roadmap on – and ensure sufficient resources are allocated to – delivering the critical roadmap elements that enable market participation (e.g. technical standards) and provide consumer protections

3.23 Progress on priority CER reforms is critical to protect consumers and enable efficient market participation

The Energy and Climate Ministerial Council endorsed the National CER Roadmap in 2024 to build national consistency and support a harmonised approach to unlocking the full potential of CER. The roadmap aims to ensure efficient and effective CER uptake, spreading benefits equitably, including in jurisdictions that choose to provide subsidies to accelerate investment.

The Panel notes the high priority ministers have given to delivering reforms under the CER Roadmap; and the efforts to deliver a complex work program with multiple competing stakeholder demands. Stakeholders are strongly supportive of the work of CER reform and have noted delays in some CER national reform priorities.

The Panel recommends, if resources to concurrently deliver all elements of the roadmap cannot be found, some elements should be prioritised. The Panel endorses the following existing reform priorities as ones likely to create better outcomes in the wholesale market that benefit consumers.

- **Extending consumer protections for CER (due in 2026)**

  This reform (CER Roadmap priority C1) extends consumer protections to new energy services, ensuring coverage for the full scope of CER products. Stakeholder consultations have highlighted concerns about risks to consumers associated with new energy service products and handing over control of their CER assets to retailers. Clear consumer protections will build trust and maximise consumer engagement. This is critically important to complement the Panel's recommendation that aggregations of price-responsive CER should be visible (**Recommendation 2**). Consumer protections for CER are discussed further in **Chapter 6: Ensuring consumers benefit**.

- **National regulatory framework for CER to set and enforce standards (due by end of 2026)**
  This reform (CER Roadmap priority T2) focuses on creating regulations for standard-setting and compliance for CER. A national framework will reduce regulatory costs, promote competition and enhance the integration of CER into the grid, improving system security and reliability. The Panel views this as a key enabler of CER integration, as inconsistent technology capabilities and a lack of standards across CER products are barriers to consumer participation in CER.
- **Data sharing arrangements (due between 2025 and 2027)**
  This reform (CER Roadmap priority M2) covers data access rights, metrics and processes for collecting CER data, including establishing a CER data exchange and improving data availability for consumers. Reliable data is crucial for forward planning, operating the power system and maximising CER value to all consumers through real-time energy trading. Industry and consumer-based stakeholders have highlighted the lack of reliable data on CER uptake and real-time energy trading as significant challenges for forward planning. This includes long-term forecasting through the ISP and the real-time challenges around generation dispatch. The key pilot projects – Project EDGE and Project Edith – have emphasised that efficient functioning of CER in the NEM is aided by interoperable communications between resources and organisations, and widespread availability of accessible data for consumers, their agents, system and network operators.[159]

The Panel has commented on reform priority M3/P5 relating to roles and responsibilities (including the Distribution System Market Operator concept) as part of Recommendation 1D not to create additional distribution-level wholesale energy markets. In addition to triaging work if required, to allow strategic focus on the highest priorities and those that require minister-level agreement, the CER taskforce could separate out relevant elements of work to established governance arrangements, where possible.

Stakeholder feedback on prioritising the CER Roadmap reforms

Stakeholders broadly agree with the Panel's prioritisation of existing reform priorities C1, T2 and M2. However, some stakeholders also consider the Panel should recommend the prioritisation of reforms to the technical standards for CER interoperability (T1), consumer pricing and network reform (M1) and redefining roles for market and power systems operations (M3/P5).[160] The Panel's recommendation relating to distribution-level markets (Recommendation 1D) is intended to inform the development of the M3/P5 reform work within the existing market structure.

In alignment with stakeholder feedback, the Panel has retained its recommendation to continue to prioritise implementation of the CER Roadmap. The success of increasing visibility and participation in dispatch of price-responsive resources (**Recommendation 2**) will be closely linked to complementary measures that enable effective CER integration and consumer participation, including ensuring resources have technical characteristics to be participative.

[159] See, for example, DEIP DER Market Integration Trials Summary Report 2, ARENA on behalf of Distributed Energy Integration Program 2023.
[160] Submissions to the NEM Review Draft Report consultation recommending prioritisation of reform T1 include EEC (p 10), ENA (p 3), Origin (p 7) and SA Power Networks (p 1). Submissions recommending prioritisation of reform M1 include Origin (p 7). Submissions recommending prioritisation of reform M3/P5 include AEMO (p 6), Ergon Energy and Energex (p 4) and Origin Energy (p 7).

Recommendation 3B: Government incentives for investment in CER, such as for batteries, should support resources that are enabled to participate actively in the market through aggregators and are ready for dynamic network connections

Government programs now offer significant support for the adoption of CER. The Panel recommends that funding from these schemes be contingent on these resources being installed in a manner that allows for them to be aggregated. To be clear, the Panel is not recommending that consumers be required to participate in VPPs or other forms of aggregation, but instead is recommending that where government incentives are provided for battery adoption the technology that would enable this should be mandatory. This will allow for consumers to choose to participate in a VPP if they wish to.

Over time, the requirements of funding schemes could be adjusted to further simplify the activation pathway for consumers who choose to sign up with an aggregation service. This approach will support earlier recommendations by making it easier for CER to participate in the market through aggregators.

Further, it is important that new CER connections are not just ready for aggregation in the wholesale market, but also ready for dynamic network connections. This ensures that CER can dynamically operate within network limits including system security backstops. Aggregation helps coordinate CER to balance energy within the system using price signals through the wholesale market, whereas dynamic connections help coordinate CER to help operate networks within their technical limits and the energy system within its secure limits.

Recommendation 4: Market bodies should use the rule change process to ensure the efficient and competitive functioning of the real-time energy-only spot market

Recommendation 4A: Market bodies and the ACCC should work together to develop a broader understanding of the risks and opportunities created by algorithmic bidding to inform regulatory responses, including rule changes if needed.

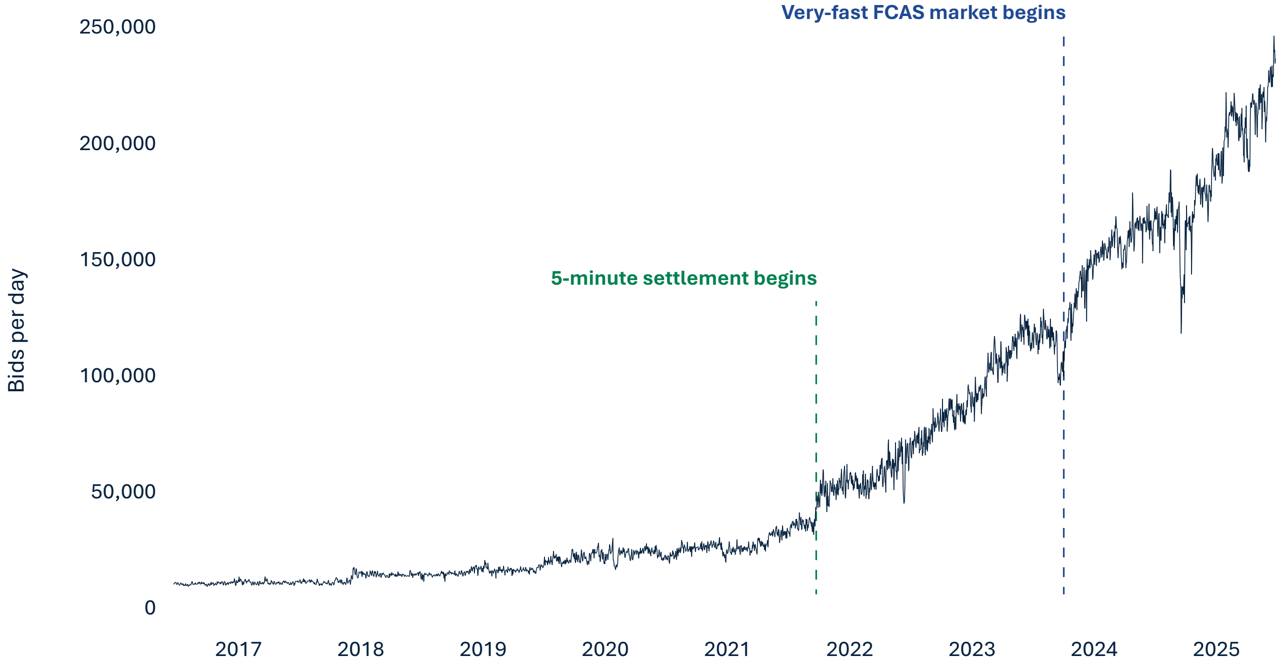
3.24 Suppliers are rebidding energy at an increasing rate

Bidding energy supply at higher prices, even at short notice, is part of the market's design. Rebidding allows generators to respond to changing conditions and information, which is crucial for a spot market that reflects real-world conditions at the time of dispatch.[161] Bidding that increases prices is legitimate if it reflects scarcity, as short periods of high prices allow generators to earn a return on their investment and provide a signal for new resources to enter the market.[162] As noted earlier in this chapter, it is important that the efficient mix of generation earns sufficient revenue to recover both short- and long-run costs.

However, the significant increase in the volume of bids in recent years (Figure 41) has raised regulatory and governance concerns.[163] The reliance on autobidding software further complicates these issues, as opaque algorithms can hinder regulators' ability to scrutinise market behaviour and ensure compliance.[164]

[161] AER (2024), Wholesale energy market performance report 2024, p 158.
[162] Ibid.
[163] AEMC (2025), AI and the future of energy regulation - algorithmic collusion, p 13.
[164] Chan, J. (2021), Algorithmic collusion and Australian competition law: trouble ahead for the National Electricity Market?, UNSW Law Journal, p 1368.

Figure 41 – Number of bids by NEM participants per day, July 2016 to June 2025



Source: NEM Review analysis of AEMO MMS data (rows per day in the "BIDDAYOFFER" table).

3.25 Regulations prohibit misleading bids, but they are difficult to detect

The NER oblige market participants to not make false or misleading bids, which are bids that participants have no genuine intention to honour or are made without a reasonable basis.[165] The rules also require participants to always have appropriate staff (not machines) available to respond to instructions from AEMO.[166] Additionally, the NER require the AER to monitor and report on factors that contribute to significant price outcomes,[167] including rebidding specifically.[168]

The AER's reports on high-price events during 2024 found that rebidding was a common driver of these events, while noting that all events had multiple drivers.[169] The regulator's wholesale market performance report for 2024 also discussed battery bidding behaviour, noting that batteries often make hundreds of rebids in a day, relying on autobidding software.[170] However, the AER found it difficult to interpret whether this rebidding was excessive or simply responsive, noting: "It can be difficult to distinguish between battery rebids that reflect changing costs and those that reflect a lack of competitive constraint or exercise of market power to put upward pressure on prices." Importantly, operators of large-scale batteries informed the Panel that the constant rebidding is necessary for batteries to comply with their obligations under the NER. Even small changes to their state of charge require updates to all future periods, as their intentions have slightly changed.

[165] AEMC (2025), National Electricity Rules, version 227, clause 3.8.22A.
[166] Op Cit., clause 4.9.2(d).
[167] Thirty-minute periods where the average spot price exceeds $5,000/MWh. See AER 2022, Significant price reporting guidelines, p 3.
[168] AEMC (2025), National Electricity Rules, version 227, clause 3.13.7(b)(2)(iii).
[169] For example: AER (2024c), Electricity prices above $5,000 per MWh, October to December 2024, p 2.
[170] AER (2024), Wholesale energy market performance report 2024, p 93.

3.26 Algorithmic bidding may facilitate non-competitive outcomes and price distortion

Regulators have held concerns that widespread use of algorithmic bidding could undermine competition and lead to non-competitive outcomes.[171] [172] Many machine-learning models used in autobidders are opaque, meaning the rationale behind their decisions cannot be scrutinised. Algorithms could collude even without the knowledge of the parties on whose behalf they bid,[173] for example, by using pre-dispatch to send tacit signals to other bidders. The AEMC has documented how this kind of signalling, built into an algorithmic bidding strategy, can lead to much higher payoffs for generators despite them risking only a “very small percentage of their total offered quantity”.[174]

The NEM’s characteristics – its size, five-minute energy intervals and 10 frequency markets, including at the one-second interval – make it potentially susceptible to algorithmic collusion.[175] [176] Many generators already use machine-learning models to bid. A recent University of New South Wales study suggested that the significant increase in the number of bids in the NEM at least partly explained a corresponding rise in pre-dispatch price uncertainty.[177]

Despite these concerns, algorithmic tools can help participants use market information more effectively, improving market efficiency. Restricting their use completely is unlikely to benefit consumers.

Stakeholder feedback on the risks and opportunities created by algorithmic bidding

The Panel heard from a range of stakeholders regarding its recommendation in the Draft Report and consultation question on the impact on dispatch of increased algorithmic bidding. There was general support for the draft recommendation with many stakeholders noting the need for market bodies to better understand the opportunities as well as risks of algorithmic bidding to then inform mitigation approaches, including regulatory responses.[178] Stakeholders emphasised the need for any regulatory responses to balance the needs of system and market integrity with those of investor flexibility and industry innovation, so as to not limit the potential benefits of algorithmic bidding.[179] There was strong support for market bodies further developing their capabilities in this field and consulting closely with industry on existing and emerging technologies and practices. The Panel has updated its final recommendation in response to stakeholder feedback received.

[171] Ezrachi, A. & Stucke, M. E. (2017), ‘Artificial intelligence & collusion: when computers inhibit competition’, in University of Illinois Law Review, p 17–75.
[172] AEMC (2025), AI and the future of energy regulation - algorithmic collusion, p 12.
[173] Ben-David, R. (2023), ‘Rethinking markets, regulation and governance for the energy transition’, prepared for the *ACCC/AER 2023 Regulatory Conference*, p 22.
[174] AEMC (2025), AI and the future of energy regulation - algorithmic collusion, p 15.
[175] Chan, J. (2021), ‘Algorithmic collusion and Australian competition law: trouble ahead for the National Electricity Market?’, in *UNSW Law Journal*, p 13–68.
[176] AEMC (2025), AI and the future of energy regulation - algorithmic collusion, p 15.
[177] Prakash et al. (2025), The Scheduling Role of Future Pricing Information in Electricity Markets with Rising Deployments of Energy Storage: An Australian National Electricity Market Case Study, in Energy Economics, p 108–191.
[178] Submissions to the NEM Review Draft Report consultation from ACTU (p 6), AEMC (p 16), AGL (p 7), Alinta (p 8), CEIG (p 5), EDF Power Solutions Australia (p 4), ETU (p 20), JEC (p 3) and SACOSS (p 3).
[179] Submissions to the NEM Review Draft Report consultation from AEC (p 6), CEIG (p 5) and Snowy Hydro (p 4).

The NEM requires updated oversight of these emerging risks. The Panel has revised **Recommendation 4A** in response to stakeholder feedback. The scale of algorithmic bidding is likely to continue to increase as more trading portfolios use algorithmic software to manage bidding. Appropriate governance, standards and regulatory oversight will be essential to ensure that these tools improve market efficiency.

The Panel recommends that market bodies establish a program of work to:

- develop a broader understanding of the risks, benefits, scale and nature of algorithmic bidding and any resourcing requirements to ensure they can effectively address these challenges, and
- identify and implement rule changes and regulatory responses, if needed, to address these challenges.

Recommendation 4B: Market bodies should analyse whether publishing battery state of charge information from July 2025 adequately mitigates reliability risks or whether further reforms are needed

The recent Enhancing Reserve Information rule change has improved the market's visibility of forecast and actual state of charge information for batteries, and the energy limits of other assets.[180] As of 1 July 2025, AEMO began publishing:

- The previous trading day's five-minute data for individual utility-scale batteries.
- The aggregate state of charge of each region's battery fleet in real time.
- The forecast aggregate state of charge of each region's battery fleet in the:
  - five-minute short-term projected assessment of system adequacy (ST PASA) up to 1 hour before dispatch, and
  - 30-minute ST PASA from 1 hour before dispatch to the end of the next trading day.

The AEMC determined that this information would help participants make more informed operational decisions.[181] An expected benefit is that storage assets will respond more effectively to risks such as lack of reserve events by retaining charge until the network requires it.[182]

AEMO has noted it observes batteries, operating in a commercially rational way, discharge significant portions of their charge before peak demand. It agrees that publishing state of charge information should improve market operations and has implemented aspects of the rule change two years earlier than required. However, AEMO also argues that this intervention alone might not ensure that the battery fleet supports reliability when supply is tight.[183] As the NEM becomes more dependent on variable generation, AEMO expects to rely increasingly on energy-limited plant generally – not only batteries – to maintain reliability.

[180] AEMO (2024), Enhancing reserve information – high level implementation assessment, p 4.
[181] AEMC (2024), National Electricity Amendment (Enhancing reserve information final determination) Rule 2024, rule determination, p 33.
[182] Ibid.
[183] AEMO (2023), Submission to the AEMC on an operating reserve market, p 2.

The Panel believes it is important to assess whether this recent rule change is adequate or whether further reforms will be needed. It recommends that market bodies analyse how the publication of state of charge information affects the operation of batteries and other energy-limited plant. Participants' use of algorithmic bidding based on enhanced publication of state of charge and energy-constraint information will also be an important consideration, highlighting the link between **Recommendation 4A** (above) and **Recommendation 4B**.

Stakeholder feedback on battery state of charge information

The Panel heard from a range of stakeholders regarding its recommendation in the Draft Report on battery state of charge information and consultation question on what additional market information could be made public to help achieve the NEO. The majority of feedback was supportive of the recommendation.[184] Many stakeholders considered that the new reporting AEMO undertakes as of 1 July 2025 under the Enhancing Reserve Information rule change needed more time to be effective in improving market operations and that further transparency measures should therefore be considered at a later time.[185] The Panel considers that market bodies should further consider this issue once the impacts of the 1 July 2025 rule change have been clearly observed.

Recommendation 4C: Market bodies should work to minimise the impact of transmission network outages on the energy-only spot market

The AER should continue to work with the AEMC and AEMO to replace the suspended market impact component (MIC) of the regulatory framework. The AER should also continue to review whether network constraints affect competition and drive high spot prices, and progress rule changes to the AEMC if required.

3.27 Network outages need to be balanced with market outcomes

TNSPs periodically take lines out of service for maintenance, vegetation management or to connect new generation. These activities can temporarily reduce network capacity and increase spot prices by limiting electricity flows, making careful planning essential. TNSPs must notify AEMO of all scheduled outages under the Congestion Information Resource guidelines.[186] AEMO publishes this information via the Network Outage Scheduler and approves outages only if system security and reliability are maintained. Outside of notification, TNSPs have limited incentives to reduce the impact of their activities on wholesale prices.

[184] Submissions to the NEM Review Draft Report consultation from AEMC (p 17), BlueScope (p 5), CS Energy (p 7), Eku Energy (p 2), Energy Australia (p 7) and EUAA (p 5).
[185] Submissions to the NEM Review Draft Report consultation from Akaysha Energy (p 7), EDF Power Solutions Australia (p 4), Eku Energy (p 2), Fluence (p 10), Origin Energy (p 8) and Tesla (p 9).
[186] AEMO (2021), Congestion information resource guidelines, p 7–8.

Regulatory mechanisms play a crucial role in shaping TNSP behaviour. The Service Target Performance Incentive Scheme (STPIS) has been the primary tool, though it focuses broadly on network reliability. It has three components:[187]

- **Service Component:** Incentivises fewer and shorter supply interruptions.
- **Market Impact Component (MIC):** Encourages TNSPs to schedule outages to minimise wholesale market disruption.
- **Network Capability Component (NCC):** Supports low-cost projects that improve market outcomes and benefit consumers.

In a recent review, the AER strengthened the NCC to make it more effective but suspended the MIC.[188] The suspension was driven by TNSPs often facing maximum penalties, regardless of their actions, due to a rise in MIC events linked to the energy transition. Specifically, the move from centrally located thermal generation to geographically dispersed and weather-dependent generation, has created new demands on the transmission network with implications for how TNSPs manage their assets. In practice, this has increased the number of binding constraints on the transmission network and more MIC penalty events, with most TNSPs incurring maximum penalties for circumstances that may be beyond their control. The AER has noted that if a TNSP knows it is likely to occur maximum penalties under the MIC irrespective of its actions, its incentive to manage outages is significantly diminished.

The Panel supports the AER's decision to strengthen the NCC due to its value in supporting high-value projects like dynamic line ratings, which can reduce generator curtailment by enabling greater energy transfer through transmission lines under suitable weather conditions.[189]

Given the potential price impacts of network outages, the Panel advocates for stronger incentives for TNSPs to consider wholesale market effects in their planning. A revised, price-based mechanism could deliver clear, market-aligned signals or, alternatively, a conduct obligation could address market impacts without imposing excessive penalties. A targeted mechanism is essential to protect consumers and market outcomes while enabling essential works.

The Panel notes that the AER has established a working group to consider alternative options to the MIC. The working group includes representatives from AEMO, the AEMC, TNSPs, generators and consumers with the process expected to conclude by mid-to-late 2026. The outcomes of the working group process are intended to inform an AER update of the STPIS.[190] The Panel supports this work and recommends the AER initiates early work where it can streamline the process between receiving and actioning the working group's outcomes.

3.28 Reduce opportunities to exploit market power during network outages

Temporary network constraints can temporarily increase market power for participants, allowing them to rebid in ways that elevate spot prices. For example, in New South Wales in May 2024, a planned outage on the Collector–Yass transmission line prevented up to 1,400 MW of low-cost generation from reaching major load centres, including Sydney.[191] During high-price intervals, unconstrained

[187] AER (2025), Service target performance incentive scheme version 6, Clause 2.2(a).
[188] AER (2025), Service Target Performance Incentive Scheme – Final Amendments: Explanatory Statement, p 2, 11.
[189] Ibid.
[190] AER (2025), Service Target Performance Incentive Scheme – Final Amendments: Explanatory Statement, p 13.
[191] AER (2024), Wholesale electricity market performance report 2024, p 72.

generators contributed to price spikes by rebidding capacity above $5,000/MWh, behaviour facilitated by network limitations and unplanned coal unit outages.[192]

There is a growing risk of such market dynamics intensifying due to delays in transmission expansion and unexpected outages of the ageing coal fleet, leading to more frequent network constraints. These conditions create opportunities for strategic rebidding, further increasing price volatility. Therefore, the Panel recommends that the AER prioritises reviewing how network constraints resulting from outages driving high spot prices affect competition and progresses rule changes if required. This would be complementary to the existing work being done by the AER through its Wholesale Electricity Market Performance Report,[193] and could be an area of focus in 2026.

Stakeholder feedback on minimising the impact of transmission network outages

Stakeholder submissions that addressed this topic broadly supported the AER's work to find a suitable replacement to the suspended MIC.[194] Network representatives that supported the MIC's suspension still welcomed the opportunity to work with market bodies to develop pragmatic and workable approaches to minimise the impacts of transmission outages on consumers.[195]

While the recommendation to reduce opportunities to exploit market power during network outages was recognised as having the potential to improve market efficiency, competition and affordability,[196] some stakeholders warned against this work leading to regulatory interventions in the spot market.[197] The Panel acknowledges these perspectives and maintains that the AER has an important role in continuing to monitor the impact of network outages on wholesale prices.

[192] As APA noted to the NEM Review, this issue differs from price spikes caused by ageing generator outages, which provide price signals to encourage market entry (APA (2025), Submission to the NEM Review Draft Report consultation, p 8).
[193] AER (2024), Wholesale electricity market performance report 2024, section 4.3.
[194] Submissions to the NEM Review Draft Report consultation from CEC (p 5), EDF (p 4), ENGIE (p 6), EUAA (p 5) and Origin (p 8).
[195] Submissions to the NEM Review Draft Report consultation include ENA (p 1) and Transgrid (p 7).
[196] For example, BlueScope (2025), submission to the NEM Review Draft Report consultation, p 5.
[197] For example, ENGIE (2025), submission to the NEM Review Draft Report consultation, p 6.

Recommendation 5: The Reliability Panel should consider adjusting the form of the market price settings over time

> The Reliability Panel should provide a long-term outlook on the form of the market price settings as an enduring and ongoing responsibility. It should undertake a review in 2026 which provides an initial long-term outlook on the form of the market price settings and the appropriateness of the form of the settings for the future electricity market.

The market price settings, including the Market Price Cap (MPC), Market Price Floor (MPF), Cumulative Price Threshold (CPT) and Administered Price Cap (APC), should remain linked to the value of customer reliability (VCR) and to revenue adequacy for efficient investment in bulk energy, shaping and firming services. However, given the significant changes expected in the market and the intention of recommendations in other chapters to extend price discovery over decadal timeframes, the Reliability Panel should provide a longer-term outlook (up to 15 years) on the intended form of the market price settings to support long-term contracting and also consider whether the form should evolve over time.

3.29 The reliability standard is a core element of the NEM framework for delivering reliability

The reliability standard defines the maximum expected amount of energy at risk of not being served in a region in a given financial year, currently set at 0.002% unserved energy (USE). Every four years the Reliability Panel reviews the reliability standard and settings to assess their appropriateness and effectiveness in meeting market, participant and consumer requirements.[198]

The VCR is a central input into this process, reflecting how much consumers are willing to pay to avoid wholesale market-related outages. Determined by the AER through direct customer engagement, the VCR ensures the reliability standard balances reliability outcomes against the cost of achieving them.

3.30 The MPC is a lever to incentivise supply and investment to deliver the reliability standard

Previously referred to as the value of lost load, the MPC sets the maximum price that can be reached in the spot market during any dispatch or trading interval. It plays a critical balancing role – ensuring there is sufficient incentive for generators to invest, while protecting consumers from paying more than the value they place on reliable electricity supply (the VCR).[199]

[198] AEMC Reliability Panel: responsibilities and obligations.
[199] AEMC (2022), Final report: 2022 Review of the reliability standard and settings, p 63.

A high MPC provides strong incentives for generation and demand response to activate during peak system stress events.[200] Modelling undertaken by the Reliability Panel identifies the marginal new entrant required to meet the reliability standard and the price-duration combination that aligns with the level of reliability consumers value. Under the current framework, this marginal unit is often modelled as an open-cycle gas turbine or other fast-start peaking generator. The objective is to ensure that this unit, operating during scarcity conditions for a small number of hours, can recover its fixed and variable costs through a plausible number of high-price events.

3.31 The MPF signals supply surpluses and limits participants' financial exposure

The MPF places a lower limit (currently -$1,000/MWh) on dispatch prices in the wholesale market. It allows the market to clear during low demand periods while maintaining system stability and limiting participants' financial exposure.[201] The Reliability Panel may only recommend an MPF that allows the market to clear in most circumstances without posing significant risks to market integrity.[202]

3.32 The CPT and APC also limit participants' financial exposure

The CPT is the rolling total of seven days of trading prices in a region which, if breached, triggers an administered price period, during which the APC limits spot prices to $600/MWh. The APC and CPT work together to limit market participant financial exposure to prolonged high prices, maintain pricing signals for new developments and support the achievement of reliability standards.[203] The APC acts as a 'last-resort safety' tool, ensuring generators can recover short term costs and incentivise continued operation.[204]

After the June 2022 market suspension, the AEMC raised the APC to a level sufficient for peaking generators to recover a higher short-run marginal cost and to encourage generators to continue participating in the normal dispatch process.[205] By allowing more cost-reflective bidding from generators during an administered price period, the market can find the least-cost solution to dispatch in real time, rather than relying on directions from AEMO to meet reliability requirements.[206]

International comparisons

International wholesale electricity markets use various frameworks to balance the need to incentivise investment and ensure system reliability while protecting consumers from extreme price volatility. In energy-only markets such as the NEM the MPC tends to be set relatively high for generators to recover their fixed and variable costs solely through the spot market. The MPC needs to reflect the value consumers place on uninterrupted supply. The NEM's MPC, currently set at $20,300/MWh,[207] is among the highest globally. The high MPC ensures that during periods of scarcity, prices can provide revenue sufficiency for generation capacity that is only needed infrequently. Importantly, most consumers are not exposed to these prices; rather, retailers

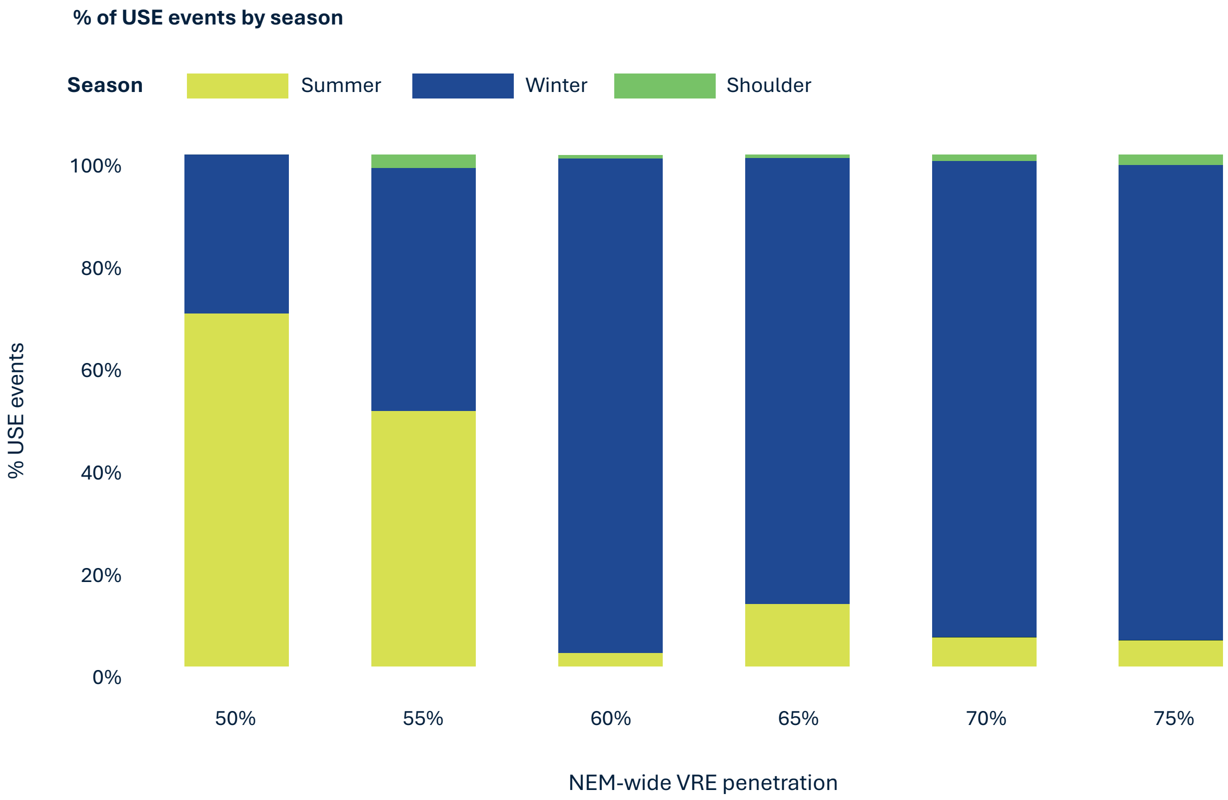
[200] AEMC (2025), submission to the Initial NEM Review consultation, p 12.
[201] AEMC (2022), Final report: 2022 Review of the Reliability standard and settings, p 99.
[202] Op. cit., p 100.
[203] AEMC (2022), Information sheet: Amending the administered price cap, p 2.
[204] Ibid.
[205] AEMC (2022), National Electricity Amendment (Amending the administered price cap) Rule 2022, p 2.
[206] Op. cit., p i.
[207] The market price cap as of 1 July 2025.

manage the risks on their behalf through the procurement of cap contracts, which act as a form of decentralised capacity market. In contrast, centralised capacity markets provide generators with an additional revenue stream through capacity payments, which remunerate them for being available to supply electricity. Capacity markets generally set a lower MPC because capacity payments reduce the reliance on scarcity pricing to ensure revenue sufficiency.

3.33 The transition is challenging current market price settings

The NEM's increasing weather dependency and system volatility (discussed in **Chapter 2: Trends and challenges in the NEM**) mean that the nature of extreme reliability and high-price events is changing. Historically, unserved energy events and the resulting high-price events were generally concentrated during short periods of high summer demand, often driven by thermal plant outages. However, these risks are increasingly shifting towards winter, where lower solar output and prolonged low-wind conditions create risks to reliability. These events are projected to become more frequent and prolonged in a high penetration renewable system, creating new types of challenges for system reliability.

Figure 42 – Reliability risk is expected to shift from summer to winter



Source: AEMC (2023), Directions Paper: Review of the form of the reliability standard and APC, p 26.

The Reliability Panel's 2024 review of the reliability standard noted current market price settings alone could not incentivise the investment needed to manage the risk of severe, low-probability events without placing an excessive cost burden on consumers. While the market price settings should remain the primary signal for meeting the reliability standards, the NEM Review Panel has recommended that the Reliability Panel provide annual advice to jurisdictions on the costs and benefits of procuring additional out-of-market reserves to deal with these types of events (see **Recommendation 10D**).

In the absence of greater contracting activity (see **Chapter 4: Maintaining liquidity in the derivatives market**), firming generators may face growing revenue unpredictability due to the increasing unpredictability of high-price events with rare weather conditions.

A higher MPC can improve investment viability for peaking and long-duration storage assets, as these assets are often financed using derivatives such as cap contracts. Market price settings strongly influence the structure and terms of these contracts and the level of risk that contracted parties are exposed to.

For example, a higher market price cap increases the potential amounts that a generator may need to pay to a contract counterparty under a $300 cap contract when prices exceed $300/MWh. Some stakeholders argue the existing MPC incentivises short-duration storage over longer-duration firming assets.[208] AEMC modelling has found the MPC supports the entry of traditional peaking plants like open-cycle gas turbines but is unlikely to support higher-cost or more capital-intensive technologies, such as pumped hydro.[209]

3.34 The Reliability Panel should provide a longer-term outlook on the form of the market price settings

Market price settings (particularly the MPC, CPT and APC) play a significant role in shaping expected future revenue opportunities and allocation of risk in the NEM and, in turn, prices in the derivatives market.[210] Currently, the Reliability Panel reviews and recommends changes to the reliability standard and settings, including the market price settings, every four years. While this provides medium-term certainty, it is limited in its ability to support longer-term planning and contracting. With the ESEM proposed to procure contracts over the longer-term, both the market and the ESEM Administrator will require a much longer-term perspective on market price settings to appropriately value ESEM contracts (see **Recommendation 10**).

Long-term investment and pricing of contracts requires market participants to have a degree of confidence in the form of market price settings into the future. As the generation mix shifts from thermal generation to firmed renewables and more flexible demand-side resources, investment in technologies like batteries and demand response becomes increasingly important. These technologies have distinct revenue profiles: for example, long-duration batteries benefit from sustained high-price periods, while demand response may depend on sharp, short-duration peaks.[211] A forward-looking outlook would provide the clarity needed for participants to price longer-term contracts and commit to long-term investment, while allowing the market to shape the right balance of incentives and risks over time.

In response to the Draft Report, stakeholders supported the principle of a forward-looking outlook but noted the inherent limitations of long-term forecasts.[212] The NEM Review Panel has engaged

[208] Dr Sarah Lawley (2025), submission to the Initial NEM Review consultation, p 1.
[209] AEMC (2023), Rule determination: National Electricity Amendment (Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap) Rule.
[210] AEMC (2022), Final Report: Review of the Reliability Standard and Settings.
[211] Rangarajan et al. (2025), 'Revisiting the Crisis: An Empirical Analysis of the NEM Suspension', in Energy Economics.
[212] Submissions to the NEM Review Draft Report consultation on forecast unreliability include Akaysha (p 8), Fluence (p 11), Clean Energy Council (p 4), AGL (p 7) and IEEFA (p 12). Submissions noting the role in supporting long-term investment and contracting included

directly with the Reliability Panel on how a long-term outlook could be operationalised and is confident the Reliability Panel can develop a valuable model, and provide initial formal guidance as part of a stand-alone review in the first half of 2026. The long-term outlook should provide qualitative guidance, without necessarily specifying expected values, to give market participants visibility into how the settings could evolve in response to system needs and emerging technologies. This proposed approach reflects the NEM Review Panel's engagement with the Reliability Panel and stakeholder feedback received on the need for flexibility, while preserving the core objective of supporting market participants' confidence in longer-term investment and contracting decisions.

Following the stand-alone review, the NEM Review Panel recommends that the long-term outlook become an enduring and ongoing responsibility of the Reliability Panel. This leverages the Reliability Panel's existing governance arrangements and its role in delivering independent advice that reflects a diverse range of market perspectives and technical expertise. It is proposed that the long-term outlook be undertaken every four years, as part of the Reliability Panel's existing four-yearly review of the reliability standard and reliability settings. The NEM Review Panel is pleased to note the Reliability Panel's willingness to adopt this new responsibility (see section 2.3 of the **Supplementary Materials**).

In developing and providing its long-term outlook, the Reliability Panel should consider:

- Identifying triggers for when and how it would reassess the appropriateness of the form of the settings and how the settings themselves could change.
- Allowing for adjustments when necessary to respond to unforeseen circumstances or system changes.
- Underpinning investment confidence and supporting long-term contracting by increasing confidence in the form of the market price settings.
- Guiding the continued evolution of derivative market products to ensure contract market efficiency.
- The evolving nature of the value of customer reliability and its measurement, ensuring customers pay prices that reflect what they value.

The long-term outlook should be developed concurrently and informed by the industry-led contract co-design process facilitated by the AER and ESEM Administrator (**Recommendation 7**), enabling shared learnings and coordination. The Panel recommends that the Reliability Panel's regular Reliability Standard and Settings Review process, including the long-term outlook, and the enduring industry-led contract co-design process be conducted on the same cadence to enable collaboration and alignment between the two processes. Market price settings play a critical role in shaping expectations around future revenue opportunities and the allocation of risk. These interactions should inform the Reliability Panel's enduring framework to provide a long-term outlook.

3.35 Reliability settings may need to change over time to accommodate the transition

The market price settings were originally designed for a system dominated by a single marginal peaking fuel source. The NEM is now transitioning to a system where a range of technologies can set prices during scarcity events at different timescales, both intraday (e.g. batteries during evening peaks) and over longer multiday seasonal events (e.g. gas-fired turbines or very long duration storage during low

ActewAGL (p 1), Snowy Hydro (p 5), EMX Energy (p 4) and Squadron (p 3).

renewables periods). This shift in physical characteristics is driving more predictably variable and unpredictably volatile prices. Market price settings will continue to define the boundary of market risk, shaping future revenue opportunities, risk allocation and in turn, prices in derivative markets.[213] To ensure these settings continue to deliver efficient outcomes for market participants and consumers, the NEM Review Panel recommends assessing the form of the settings in the context of the evolving physical system and emerging technologies as part of the stand-alone market price settings review.

The NEM Review Panel recommends keeping the MPC aligned with the VCR and the cost of new entrants. The NEM's high MPC reflects the value customers place on reliable electricity (VCR) and ensures generators can recover their costs. Maintaining this balance is essential to support the timely delivery of new capacity ahead of thermal generation retirements, ensuring ongoing system reliability. If the MPC is too low, then not enough required generation will be built, leading to blackouts, even when customers are willing to pay a higher price to avoid such outages. This recommendation works in tandem with the ESEM's objective of purchasing derivative contracts at the lowest cost of supply for new entrants through a competitive tender process. When these contracts are recycled back to the market, their value will depend on prevailing supply and demand (market prices).

As the energy system evolves, different technologies are increasingly providing marginal supply under different circumstances. For example, behind-the-meter batteries are increasingly well suited to shifting supply within a single day by charging when solar generates and discharging into the evening peak (creating a partial grid substitute). However, they can't sustain output through extended periods of low renewable generation in winter. These events are projected to become more frequent and prolonged in a high-penetration renewable system.[214] During such periods, firming technologies such as gas or long-duration storage (such as hydro) are likely to continue to be an important technology for providing capacity that can generate for sustained periods of time (but not bulk energy). Their usage will become more concentrated, particularly during winter periods. However, the CPT effectively caps the potential of firming, creating revenue sufficiency concerns for firming generation if it is set too low.

Hypothetical examples of alternative forms of market price settings

Greater demand flexibility can help smooth spot market price spikes and reduce the frequency of prices hitting the MPC or breaching the CPT.[215] In this context, the hypothetical example of a 'stepped' market price cap could provide differentiated signals for the types of technology needed by the system, for example:

- a very high cap (e.g. current market price cap) for a short period of time (e.g. 2–4 hours each day) to incentivise particular types of batteries and demand response; and
- a reduced high cap (e.g. $5k/MWh) applied for a longer time period following the very high cap period (e.g. 4–24 hours) to incentivise firming technologies that are required to meet prolonged periods of very low renewable output.

Another alternative approach could involve an inframarginal administered price cap, which distinguishes between marginal and inframarginal generators under an APC. Under this model, once the CPT is reached, firming and long-duration shaping generators would continue to

213 AEMC (2022), Final Report: Review of the Reliability Standard and Settings.
214 AEMC (2023), Directions Paper: Review of the form of the reliability standard and APC, p 26.
215 D Biggar and M Hesamzadeh (2024), 'Crisis in Texas and Australia: failures of energy-only markets or unforeseen consequences of price caps?' in Energy Economics.

receive revenues from the market price, while all other generators receive the administered price until the end of the administered pricing period. A relevant precedent is the European Commission's temporary inframarginal revenue cap introduced in 2022 in response to sustained high prices.[216] The temporary cap applied only to inframarginal generators using technologies with lower marginal costs, while marginal units were unrestricted and able to fully benefit from high prices.[217]

By way of example, in the future NEM, the inframarginal and marginal units could be determined by the services initially procured by the proposed ESEM – bulk energy, shaping and firming. Inframarginal units could be defined as those providing bulk energy services (e.g. solar and wind) and marginal units defined as firming and long-duration shaping services (e.g. gas, pumped hydro, hydro). The inframarginal price cap would apply only to inframarginal units, which are settled at the APC (currently $600), while marginal units would continue to receive the market spot price.[218]

These hypothetical examples demonstrate alternative constructs of market price settings. To be clear, the Panel is not recommending either of these be adopted, but instead is recommending that the Reliability Panel consider this issue on an ongoing basis. The most appropriate form of market price settings for the NEM beyond 2030 will be determined by the pace of its transition and its nature, including the technologies underpinning its secure and reliable operation. As such, the NEM Review Panel recommends the Reliability Panel, as part of the proposed review to provide a long-term outlook on the form of the market price settings, also considers the appropriateness of the form of the settings for the future electricity market.

In the stand-alone review, the Reliability Panel may want to consider how market price signals can be targeted and relevant to the type of services and technology profile needed in the system, including ensuring new service categories (bulk energy, shaping and firming) can achieve revenue adequacy for an optimal mix of investments. It is important to consider the interaction between the market price settings and contract market efficiency, noting the interactions with the NEM Review recommendations in the derivatives market (for example, **Recommendation 6** and **Recommendation 7**). The stand-alone review should also consider the merits of alternative approaches to the form of the market price settings, such as a 'stepped' MPC and inframarginal administered price cap. The Reliability Panel may want to consider scenarios that could justify revisiting the form of the settings if it were in the long-term interests of consumers, and consider the role of the long-term outlook in signalling this to market participants.

[216] European Commission (2023), 'Report from the Commission to the European Parliament and the Council: on the review of emergency interventions to address high energy prices in accordance with Council Regulation (EU) 2022/1854,' p 3.

[217] The measure aimed to reduce the impact that the price-setting marginal generator (typically gas-fired generator) had on the revenues of low-marginal cost generators in Europe. The temporary revenue cap applied to inframarginal generators using technologies with lower marginal costs (e.g. renewables, nuclear and coal) with the revenues above the cap used to mitigate the impact of high electricity prices to consumers. Marginal generators (e.g. gas-fired generators and battery storage) were unrestricted and able to fully benefit from high market prices.

[218] Under the current compensation framework, participants who provide services during periods of administered pricing and make a loss can make claims for compensation. Under the proposed inframarginal approach, marginal units would continue to receive the spot price. Inframarginal units (e.g. bulk energy) would receive the APC and would not be entitled to compensation payments.

Stakeholder feedback and engagement on the form of the market price settings

Long-term outlook: The Panel received broad stakeholder feedback in response to its Draft Report recommendation to establish a long-term outlook on the form of the market price settings. While most supported the intent, views varied on the model and its potential value for investment certainty and contracting. Several stakeholders agreed the long-term outlook would guide long-term planning and investment, and support stable contracting arrangements.[219] Others raised inherent challenges with long-term forecasts, noting that forecasting errors could lead to inefficient market settings over time.[220] Flexibility to respond to evolving market dynamics and technological changes was a consistent theme.[221]

Form of the market price settings: Several stakeholders supported the recommendation for the Reliability Panel to consider adjustments to the form of the settings over time, to ensure they remain effective as the system evolves.[222] They emphasised the need to consider interactions with the ESEM and potential impacts on wholesale and contract markets in any adjustments to the settings. However, some stakeholders felt there was no clear case for changes at this time.[223]

Some stakeholders provided feedback on the NEM Review Panel's hypothetical 'stepped' MPC example. Some supported further assessment, noting its potential to incentivise a balanced mix of both short- and long-duration energy storage.[224] Others raised concerns that a more granular MPC could unintentionally concentrate risk during reliability periods, add to trading and contract market complexities and discourage contract offerings at other times.[225] A small number of stakeholders proposed alternative forms, such as setting the APC as a percentage of the MPC, introducing differentiated APCs for peak and off-peak periods during administered pricing, or extending the CPT to better support long-duration storage and firming technologies.[226] The Reliability Panel, as part of its stand-alone review, should consider the merits of alternative forms of the market price settings, and the scenarios in which they may be warranted.

Reflecting stakeholder feedback and its engagement with the Reliability Panel, the NEM Review Panel has retained its core recommendation that the form of the market price settings may need to evolve over time, and that the Reliability Panel should undertake a long-term outlook. The NEM Review Panel engaged extensively with the Reliability Panel on its draft recommendations and valued its expertise and feedback in operationalising these. The final recommendation was developed with support from the Reliability Panel, giving confidence in their successful implementation.

[219] Submissions to the NEM Review Draft Report consultation from ActewAGL (p 1), Snowy Hydro (p 5), EMX Energy (p 4), Squadron (p 3) and BlueScope (p 5).
[220] Submissions to the NEM Review Draft Report consultation from AGL (p 7), Akaysha (p 8), Clean Energy Council (p 4), Fluence (p 11) and IEEFA (p 12).
[221] Submissions to the NEM Review Draft Report consultation from ENGIE (p 7), Hydro Tasmania (p 10) and Shell Energy (p 5).
[222] Submissions to the NEM Review Draft Report consultation from AEMO (p 4), CEIG (p 5), CS Energy (p 7), Enel X (p 9), Iberdrola (p 6), JEC (p 12), LDES Council (p 1), Shell Energy (p 5) and Solar Citizens (p 11).
[223] Submissions to the NEM Review Draft Report consultation from Fluence (p 11) and Origin (p 8).
[224] Submissions to the NEM Review Draft Report consultation from LDES Council (p 1) and RayGen (p 2).
[225] Submissions to the NEM Review Draft Report consultation include Alinta Energy (p 8), Eku Energy (p 3), Origin Energy (p 9) and Shell Energy (p 5).
[226] Submissions to the NEM Review Draft Report consultation recommending APC as a percentage from Shell Energy (p 6) and APC peak pricing from Eku Energy (p 3). Submissions to the initial NEM Review consultation recommending changes to the CPT include Clean Energy Council (p 9) and AGL (p 6).

4

Maintaining liquidity in the derivatives market

Chapter summary

Derivatives markets are essential to the operation of energy-only markets like the NEM. They enable participants to hedge risk and send critical medium-term signals for pricing and investment. As the spot market becomes more predictably variable and unpredictably volatile through the energy transition, access to transparent and liquid derivatives markets will only become more important.

Transparency of retailers' risk management costs increases consumers' confidence that retail prices are fair and reasonable. Transparent derivatives markets also enable the trading of contracts on fair terms and with transparent prices that reflect expected future market conditions. Derivatives markets facilitate generation and retail market competition and to help market participants establish fair value.

Effective derivatives markets must be liquid and accessible to willing participants. Currently, small and stand-alone retailers face barriers to accessing affordable hedging. Without improving accessibility, this could intensify and negatively affect competition in the NEM.

Derivatives markets are only effective if they transact the risk management products that market participants need and value. As the energy transition reshapes the types of risks that participants must hedge, market frameworks must ensure access to evolving financial energy derivatives that enable effective risk management. While innovation in energy-related financial markets is occurring, it is not at the pace required to support an effective market, particularly for exchange-traded products. Unless participants utilise hybrid generation or a portfolio of bulk energy and shaping assets, traditional hedging instruments, such as baseload swaps, are likely to become less available as thermal generators exit the market. Timely innovation is needed to mitigate the risk of declining liquidity in the NEM.

To improve transparency, accessibility, liquidity and innovation in derivatives markets, the Panel recommends reforms to:

- Establish a permanent market making obligation (MMO) framework to support price transparency and contract accessibility and improve market transparency and access for small retailers (see **Recommendation 6**).
- Institute a new industry-led contract co-design process, building on the pilot conducted by the NEM Review Panel, to define a core set of derivative products suitable for an increasingly weather-dependent system, for use in the MMO and the Electricity Services Entry Mechanism (ESEM), with the process co-convened by the Australian Energy Regulator (AER) and ESEM Administrator (see **Recommendation 7**).
- Review options to further improve accessibility and liquidity in derivative markets and increase efficiency of capital deployed as credit support (**Recommendation 8**).
- Improve the availability of market information necessary to support hedging over a longer time horizon, including by extending the generator availability information provided under the medium-term projected assessment of system adequacy (MT PASA) process (see **Recommendation 9**).

Enabling longer-term hedging is an important step in supporting participants' ability to manage risk. By adopting these reforms in the medium-term derivatives market, financial derivative contracts (rather than revenue underwriting) can then be integrated into the design of the long-term investment signal – the ESEM outlined in **Chapter 5: Unlocking long-term investment in new energy services**.

Recommendations

6 Energy ministers should establish a permanent market making obligation (MMO) framework in the National Electricity Law (NEL) and National Electricity Rules (NER) for a small number of key derivative contracts.

The MMO framework should include the following key features:

- The MMO framework should apply to contracts for all services (bulk energy, shaping and firming) defined by the industry-led contract co-design process (**Recommendation 7**) and as designated by the Australian Energy Regulator (AER).
- The AER should have the ability to add and remove designated contracts over time, responding to market developments and the outcomes of the industry-led contract co-design process. Initially, the designated contracts for firming services should be caps, and the designated contracts for combined bulk energy and shaping services should be baseload swaps.
- Once a contract is designated, the AER should be responsible for assessing whether the MMO should be triggered for that contract and in which NEM regions. The AER assessment should be based on pre-determined objective liquidity thresholds developed through consultation with industry.[227]
- The AER's decision-making on designating contracts and objective threshold for triggering the MMO for a contract should be informed by consultation with the industry-led contract co-design group (**Recommendation 7**).
- The MMO should be triggered as soon as possible in South Australia. While both caps and baseload swap contracts will be designated, the MMO should initially apply only to cap contracts in South Australia.
- Energy ministers should be able to opt out of the application of the MMO in their region.
- The MMO should cover suppliers of the relevant services in each region that are above a specified threshold, and should set requirements for minimum trading volumes and maximum bid-offer spreads with trading occurring via an AER-approved exchange and/or over-the-counter (OTC) platform.
- Energy trading businesses should also be able to act as voluntary market makers but be required to comply with the same bid-offer spread as obligated mandatory participants if they elect to trade in the MMO windows.[228]

[227] This amended recommendation reflects some stakeholder views that the MMO should only be in place where liquidity is below acceptable levels. In particular, the Panel notes that the industry-led contracts co-design group should provide recommendations to the AER on liquidity thresholds.

[228] The Panel has amended this recommendation in response to stakeholder views that non-physical participants (e.g. energy trading businesses) provide valuable liquidity but should be voluntary market makers to ensure equal market access.

7 The AER and ESEM Administrator should regularly convene an industry-led co-design process to define a small set of core derivative contracts that underpin trading activities and the MMO and ESEM.

The first co-design process should occur as soon as practicable, drawing on the findings from the pilot process conducted by the NEM Review Panel.

The contracts developed through the co-design process:

- should be able to be traded on an exchange platform
- should be the subject of market making obligation
- should be able to be traded in smaller parcels to reflect the smaller nature of individual generators (e.g. 100 kW rather than 1 MW)
- should be utilised to contract with projects through the ESEM
- could be used in retail price benchmarking.

8 Energy ministers should commission a review of counterparty risk management and prudential arrangements in the NEM, supported by a multi-agency taskforce and industry subject matter experts.

The review should recommend options to improve accessibility and liquidity in derivative markets and increase efficiency of capital deployed as credit support.

9 Energy ministers should make a rule change that extends and publishes the generator availability MT PASA projections from three to five years, to support longer-term derivatives market liquidity and price discovery.

Recommendation 6: Energy ministers should establish a permanent market making obligation (MMO) framework in the National Electricity Law (NEL) and National Electricity Rules (NER) for a small number of key derivative contracts

The MMO framework should include the following key features:

- The MMO framework should apply to contracts for all services (bulk energy, shaping and firming) defined by the industry-led contract co-design process (**Recommendation 7**) and as designated by the AER.
- The AER should have the ability to add and remove designated contracts over time, responding to market developments and the outcomes of the industry-led contract co-design process. Initially, the designated contracts for firming services should be caps, and the designated contracts for combined bulk energy and shaping services should be baseload swaps.
- Once a contract is designated, the AER should be responsible for assessing whether the MMO should be triggered for that contract and in which NEM regions. The AER assessment should be based on pre-determined objective liquidity thresholds developed through consultation with industry.
- The AER's decision-making on designating contracts and objective threshold for triggering the MMO for a contract should be informed by consultation with the industry-led contract co-design group (**Recommendation 7**).
- The MMO should be triggered as soon as possible in South Australia. While both caps and baseload swap contracts will be designated, the MMO should initially apply only to cap contracts in South Australia.
- Energy ministers should be able to opt out of the application of the MMO in their region.
- The MMO should cover suppliers of the relevant services in each region that are above a specified threshold and should set requirements for minimum trading volumes and maximum bid-offer spreads with trading occurring via an AER-approved exchange and/or OTC platforms.
- Energy trading businesses[229] should also be able to act as voluntary market makers but be required to comply with the same bid-offer spread as obligated mandatory participants if they elect to trade in the MMO windows.

A liquid, innovative and accessible energy derivatives market enables market participants to hedge risk and sends medium-term price and investment signals. The Panel's recommendations aim to support such a market through establishment of a permanent MMO framework in the National Electricity Law (NEL) and National Electricity Rules (NER) applying initially to firming services (cap contracts)

[229] As noted above, energy trading businesses refers to non-physical participants that trade energy derivatives.

in South Australia (**Recommendation 6**), establishment of an industry-led co-design process to identify core derivative contracts that could later be designated under the MMO (**Recommendation 7**) and a future review of counterparty risk management and prudential arrangements in the NEM (**Recommendation 8**).

While current challenges around liquidity and access have not yet become critical in most regions of the NEM, there are concerning trends that, if left unaddressed, could erode competition and lead to poor outcomes for consumers. As set out in **Chapter 2: Trends and challenges in the NEM**, liquidity is declining in South Australia, which is highly dependent on bulk variable renewable energy (VRE) and peaking plants, and where existing derivative contracts are increasingly less suitable. There is a risk that liquidity in other regions will experience the same decline unless contract markets evolve to keep pace with the energy transition.

Rather than waiting for these issues to escalate and require more disruptive intervention, the Panel recommends early, targeted reforms to strengthen the foundations of the derivatives markets. These measures are designed to pre-empt deterioration, promote confidence and ensure the market remains fit-for-purpose through the transition.

4.1 Innovation must keep pace with the changing market

Derivatives markets that respond to the changing generation mix and spot market will be critical for ensuring retailers and generators can continue to manage short- to medium-term spot price risk in an increasingly weather-dependent system.

Innovation has been occurring in the OTC contracts market to meet participants' needs, although this does not provide the transparency that is valuable for price discovery. Exchange-traded contract innovation is occurring too slowly and needs to keep pace with the changing wholesale market dynamics and the changing risk management needs of retailers and generators. An efficient and liquid exchange-traded contracts market is important for price transparency and accessibility.

Without these characteristics, consumers will be unable to determine whether their retail pricing is fair, and public trust in the overall electricity system and energy transition will be significantly undermined.

4.2 Innovation in financial products is not translating quickly enough to exchanges

As coal plants exit the market, new derivative products that reflect an increasingly weather-dependent system will need to be available. The Panel is aware of significant innovation that is occurring in the OTC market. However, this innovation has not translated across to exchange-based trading. Given the time it takes to develop new products, the Panel considers a structured process is needed to accelerate contract innovation on exchanges (see **Recommendation 7**).

Some stakeholders consider that derivatives markets have worked well to date.[230] However, new exchange-traded products generally require a long lead time to become available. These new derivatives are also generally variants of existing products. For example, the most successful exchange-traded contract innovation in recent years is the Australian Securities Exchange (ASX's)

[230] AGL (2025), submission to the initial NEM Review consultation, p 13; Eku Energy (2025), submission to the NEM Review Draft Report consultation, p 3.

base strip option ('swaption'), which is essentially an option to trade a strip of four quarterly baseload futures contracts for a calendar or financial year.[231] Other examples include the ASX's new morning (6–9am) and evening (4–9pm) 'super peak' futures contracts, listed from late June 2025.[232]

> *While contract markets are evolving to meet new needs, this may not occur as quickly, or pre-emptively, as the system needs. Contracts are emerging to cover 4–6 hour daily diurnal spread but less so for overnight coverage. We are not aware of contracts emerging to cover dunkelflaute.* **– Clean Energy Council**[233]

New energy derivatives are needed as the market changes. For example, solar generation is already changing market dynamics and the nature of risks. The Australian Financial Markets Association (AFMA) provided an example of the ASX's traditional 7am–10pm peak product becoming unviable with decreasing demand and very low average wholesale prices during the middle of the day.[234] As coal plants retire, the nature of market risks will change further as standalone bulk energy and shaping services are not suited to manage the risks associated with selling the same contracts that have been used in the past.

> *As renewables are unable to offer the same level of firm contracts, standard contracts in secondary markets may become harder to obtain. The role of contract markets and their preferred forms have not yet evolved to balance management of risks with exposing customers to an efficient level of price volatility over time.* **– Australian Energy Council**[235]

4.3 New and different contract types are needed to manage new and different risks

Derivatives markets need to respond to the changing generation mix and spot market dynamics. While coal generators are well suited to offering baseload swaps, VRE generators and storage are less naturally suited to being baseload swap sellers. Through Panel consultation, a representative of a generation business noted that baseload swaps would remain an attractive buy-side hedging option. However, the baseload seller would need to use a portfolio of bulk energy and firming services to be able to physically operate in a manner that meets the financial obligations of the contract. In contrast, a representative of a retail business noted baseload swaps are a function of the generation available when the NEM was formed. This stakeholder noted that products such as four-hour blocks and four-hour super peaks are a more natural product for retailer hedging with a generation fleet transitioning from large inflexible thermal plants to bulk energy, firming and shaping assets.

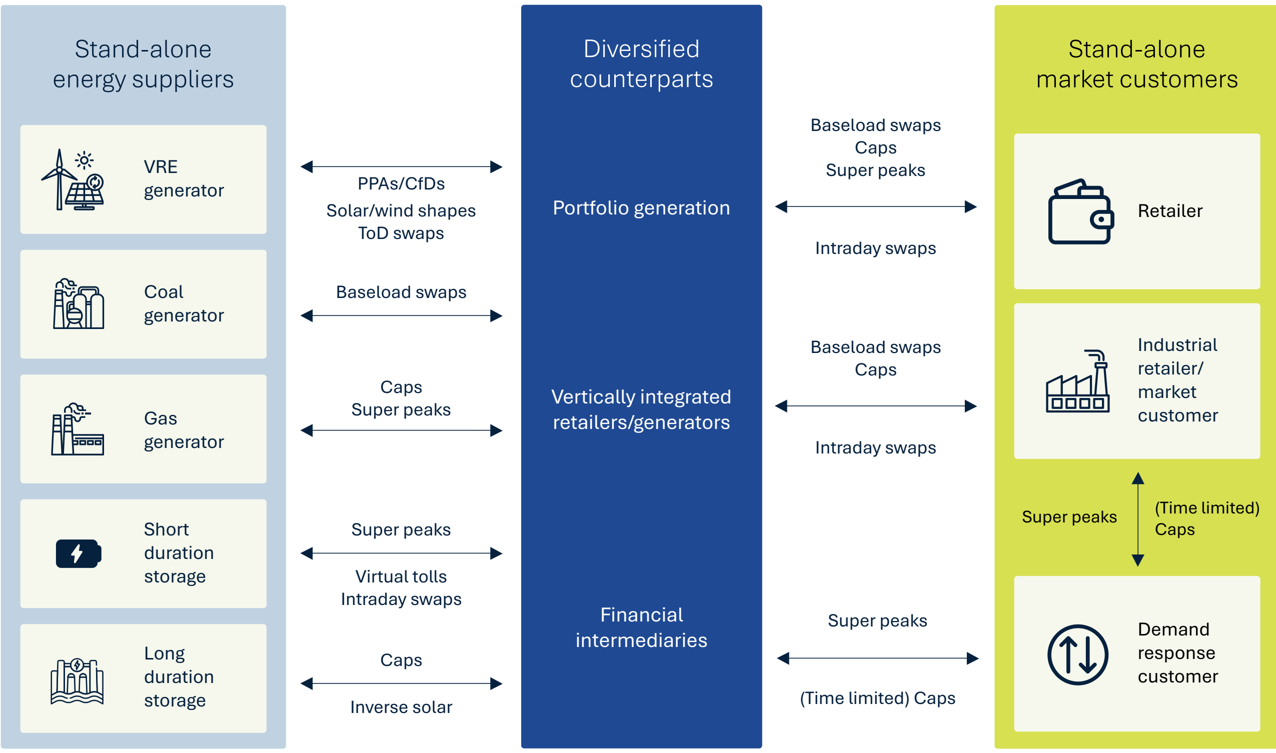
Discussions with retailers also highlighted the importance of accounting for changing load. The proliferation of small-scale solar PV, distributed energy resources and consumer energy resources has significantly altered grid demand. The resulting 'duck curve' has meant that demand is no longer

231 Swaptions have been increasingly central over the last seven years. See AER, Wholesale Energy Market Performance Report 2024, Figure 3.1, p 41.
232 ASX (2025), New Australian Peak Load Electricity Futures Trading Fees & Margins, Notice reference number: 0628.25.06.
233 Clean Energy Council (2025), Submission to the Initial NEM Review consultation, p 11.
234 AFMA (2025), submission to the Initial NEM Review consultation, p 5.
235 Australian Energy Council (2025), Submission to the Initial NEM Review consultation, p 2.

flat (baseload). A retailer noted that risk management will depend on its business model. A retailer's need to manage spot price risk is reduced with factors such as demand side response contracts that expose customers to a degree of spot price variability. Another retail business noted the importance of accounting for changing load conditions. A shifting consumer load profile may see retailers focus on hedging morning and evening peak demand and the need to hedge other parts of the day may be a risk/value judgement for individual retailers.

Figure 43 shows some of the relationships between different types of contracts and market participants. This illustrates that a range of different products are needed to meet the hedging needs of different market participants. This is consistent with what the Panel has heard from stakeholders, who suggested a range of products and strategies will be needed. These include super peak swaps, solar shaped products, standardised renewable products, storage ownership and tolling.[236]

Figure 43 – Examples of electricity derivative counterparty relationships



Note: Contracts above the arrows are exchange traded. Contracts below the arrows are over-the-counter contracts.

236 Flottmann et al. (2023), 'Derivatives and Hedging Practices in the Australian National Electricity Market', Centre for Applied Energy Economics & Policy Research.

4.4 Innovation is occurring in the OTC market

Innovation in energy derivatives largely occurs in the OTC market. OTC contracts range from bespoke contracts to standard contracts listed on closed platforms.[237] Bespoke OTC contracts can be structured to meet a participant's requirements and are more responsive to changes in market conditions, allowing for much more flexibility than exchange-traded contracts.[238]

Stakeholders provided many examples of OTC contract innovation such as solar and inverse solar shapes, storage tolling and contracts based on temperature and plant indexes. The Australian Competition and Consumer Commission's (ACCC) 2023 NEM inquiry report identified that some newer OTC products had been used by retailers and generators, but noted trades in these products were rare.[239] The CORE Markets and TOD Markets OTC platforms commenced recently, with a growing number of market participants utilising these platforms.[240]

Figure 44 – Examples of contracts for managing risk in a weather-dependent system

Contract types	**OTC bespoke** Written for individual customers	**OTC quoted** Price can be readily quoted through a broker	**OTC screen brokered trading** Limited transparency on closed trading platform	**Exchange-listed** Traded transparently on public exchange (e.g. ASX)
Weather/ production risk for VRE	VRE PPAs Wind shapes Wind/temperature index derivatives		Time-of-day blocks Solar shapes	
Changing demand profile for retailers	Sculpted profiles	Load following swaps	Time-of-day blocks Inverse solar shapes	Morning/evening peak swaps
Daily arbitrage risk for storage assets	Virtual tolls		Time-of-day blocks	
Nearer-term position adjustment			Week-ahead swaps	

Initial volumes for a new contract may be small to minimise risk as the counterparties test the contract. In the broker's case, the contract may have standardised terms to facilitate trading and reduce costs for participants.

[237] Closed platforms are private trading platforms where subscribers to the platform can buy and sell energy contracts. They offer more standardised products than one-off OTC deals. However, unlike an energy exchange they are not open to the whole market.
[238] Australian Energy Council (2025), Submission to the Initial NEM Review consultation, p 9.
[239] ACCC (2023), Inquiry into the National Electricity Market: December 2023 Report, p 76
[240] See todmarkets.com.au and coremarkets.co. Participant numbers and trading volumes are not currently publicly available, but the NEM Review Panel has heard from several participants that the platforms are increasingly used.

Speed of implementation, ease of access and allowing time to develop liquidity for a possible later move to an exchange are reasons why New Zealand's super peak contract was launched in the OTC market and not on an exchange.

Case study: Utilising the OTC market for New Zealand's super peak contract

In 2023 the Electricity Authority (New Zealand's electricity regulator) published a report 'Price discovery in a high renewables market', prepared by the Authority's Market Development Advisory Group. This report recommended the Electricity Authority work with industry to co-design new standardised flexibility products. The Standardised Flexibility Product Co-design Group was convened by the Authority with eight members selected from buyers, sellers and financial intermediaries. The Chair was nominated by the Authority from one of the Co-design Group's eight industry representatives. The Authority attended meetings in an observer and administrative role, without contributing to the agreed outcome. The Co-design Group made recommendations on a new contract, which the Authority accepted. This was subsequently worked on with industry to implement a new standardised super peak hedge contract covering morning and evening peaks.

The group decided to launch the contract on the OTC market rather than the ASX (New Zealand's primary electricity futures exchange) to achieve the following outcomes:

- Meet the three-month time frame to develop and launch the contract.[241] Listing a new product on an exchange would have taken at least 18 months.
- Allow smaller trade volumes initially, with growth over time. Listing on an exchange would have been challenging to justify without significant trading volumes.
- Facilitate access for smaller participants. Several market participants noted that exchange transaction and carrying costs were prohibitive, combined with wholesale market prudential requirements.

The group said moving the contract to an exchange would eventually be considered, if it was agreed to be beneficial.[242] The Electricity Authority engaged a broker to manage an OTC market for the new contract and it began trading 28 January 2025. On 24 November 2025, the Electricity Authority noted the product had improved risk management in the New Zealand market, with growing traded volumes and clear improvements to pricing.[243]

The Panel considers that while the derivatives market is innovating, this innovation is not available to all participants through the exchange. This could be a function of the process required for new products to be listed on exchange platforms.

Elements of this standard process help to ensure a liquid and trusted market and should be retained. However, the process has limitations as the market evolves to a firmed renewables system. This is very much a 'chicken-and-egg' type problem whereby participants do not need new products until coal plants retire and new sources of energy are generating. In many ways, this is similar to the entry-before-exit problem for investors. As such, the Panel's recommendations relate to ensuring that innovative contract types become standardised and available before coal plants permanently close.

[241] Standardised Flexibility Co-Design Group (2024), Standardised Flexibility Co-Design Group Recommendations.
[242] Ibid.
[243] Electricity Authority Te Mana Hiko (2025), 'New standardised super-peak hedge product has improved risk management'.

Achieving this will require close collaboration with industry to choose fit-for-purpose contract types for use in market making to support liquidity and long-term contracting through the ESEM (as discussed in **Chapter 5: Unlocking long-term investment in new energy services**).

The challenges of developing standard exchange and OTC contracts

In submissions to the review, several market participants welcomed the ASX's morning and evening peak futures contracts (progressively listed for each NEM region except Tasmania from late June 2025 to late July 2025)[244] but noted the contracts had taken five years to develop.

In meetings with stakeholders (including ASX, brokers and retailers) regarding contract development, the Panel heard that many factors contribute to contract development time. These can include consulting the market, determining a contract's parameters, risk and financial assessments, business case development, board approval, contract and system testing, and financial regulatory approval.

Electricity is just one of many commodities in which exchanges, clearing participants and brokers trade. Factors such as resource prioritisation and an exchange operator's strategic priorities can therefore affect when new products are introduced.

A representative from a market broker stated that it can take several years to develop a novel, standardised OTC contract. This involves ongoing customer consultation, trialling and evolving products, managing changing customer needs, dealing with market events (e.g. COVID and the war in Ukraine) and competition from other brokers developing similar products.

With broad stakeholder support, there are opportunities to expedite contract development. As set out in **Recommendation 7**, the AER and ESEM Administrator should perform an important convening role in an industry co-designed contract development process. The objective of this process should be to ensure contract designs can evolve with sufficient pace to allow for contracting to continue through the transition as the market shifts to a firmed renewable system.

4.5 Some exchange-traded market making schemes already aim to improve liquidity, but further reforms are needed

The existing Market Liquidity Obligation (MLO) and ASX voluntary market making scheme provide limited market making services that are unlikely to address looming liquidity issues.

Market making fundamentals

Market making refers to the practice of a **market maker** offering both bid (the highest price they will buy) and offer (the lowest price they will sell) quotes for standardised derivative contracts on a transparent platform, such as an exchange or through bilateral negotiations in OTC markets. They provide liquidity by ensuring buyers and sellers can transact in the market and promote price transparency through updating their prices to reflect underlying markets. A market maker benefits from the bid–offer spread and, if under a commercial arrangement, may also benefit from payment for providing the service or from incentives provided by an exchange, such as

[244] ASX Energy (2025), Launching morning and evening peak electricity futures contract.

reduced trading commissions.[245] In electricity markets, market making mechanisms are often employed to ensure that financial hedging products are available to trade, especially in periods of low liquidity or high volatility.

Market making mechanisms can be **mandatory**, **voluntary** or **commercial** (or a mix of these), with the Australian electricity derivative market currently using a voluntary scheme on the ASX.

Mandatory market making requires designated participants (often large generators and vertically integrated gentailers) to offer contracts during defined trading windows. These obligations are typically set in regulation and are designed to ensure enduring liquidity in critical contracts.

Voluntary market making involves participants choosing to provide liquidity due to commercial benefits rather than being compelled by regulation. These participants may enter into arrangements with the exchange where they receive financial benefits from meeting market making targets to buy and sell within defined parameters. Depending on the arrangement, benefits might include a fee for service, incentive payments, lower trading fees and/or preferential market access.

Commercial market making involves contracting with a third party to provide market making services. This includes frameworks under which a regulator tenders for market making services and reimburses the provider the costs of providing these services – for example, the commercial market making approach adopted in New Zealand.

The MLO was established as part of the introduction of the Retailer Reliability Obligation (RRO) in June 2019, and the ASX established a voluntary market making service in July 2019. In 2019, the Australian Energy Market Commission (AEMC) considered a rule change request to establish a market making service in the NEM. It cited the recent establishment of the MLO and ASX voluntary scheme as key factors in its decision not to introduce a new market making scheme at that time.[246]

While both changes in 2019 aimed to improve market liquidity, additional or different mechanisms are now needed to ensure derivatives market liquidity. The AEMC has noted this in its submission to the NEM Review Draft Report.

> *...replacing both the ASX voluntary market-making and MLO with a single, encompassing arrangement could provide a more reliable, efficient and nationally consistent approach to the issue. An enduring, mandatory market-making scheme has the potential to provide better price transparency and support smaller retailers entering the market. Increasing the trading intervals through an always-on design could further support the desired outcomes from the arrangements.* **– AEMC**[247]

[245] ASX (2025), Market maker arrangements webpage.
[246] AEMC (2019), Rule determination: National electricity amendment (market making arrangements in the NEM) Rule 2019, p i.
[247] AEMC (2025), submission to the NEM Review Draft Report consultation, p 20.

4.6 The MLO established a foundation for mandatory market making in the NEM but should be replaced with a stronger obligation

The MLO is a market liquidity requirement that only operates when a T-3 instrument is triggered under the RRO in response to a reliability gap forecast by the Australian Energy Market Operator (AEMO) or an energy minister.[248] The MLO aims to provide a source of derivatives for liable entities to purchase to meet contracting requirements that are placed on retailers and other large users under the RRO. It therefore operates for discrete periods and is neither broad nor enduring. It also provides for several exclusions. For example, MLO generators can miss 10 trading periods per month at their discretion – approximately a quarter of the available trading sessions.[249] The MLO is currently in effect in Victoria, South Australia and New South Wales, with market making requirements placed on EnergyAustralia, Snowy Hydro, AGL and ENGIE.[250] The MLO also has volume limits (over which the obligation is no longer required) based on net selling 1.25% (quarterly) and 10% (in the liquidity period) of the generator's registered capacity.[251] This consideration of net position is atypical for a market making obligation.

Despite its limited nature, the MLO has had some positive impact. In feedback to the NEM Review, AFMA noted that market making has been successful in the NEM and in overseas markets and enjoys wide support from their membership.[252] AFMA and the Australian Energy Council (AEC) further noted that their members generally consider the MLO has boosted liquidity and been positive for the NEM, with parties that have been obliged to act as market makers confident that they can manage the risks of being a market maker.[253] In its submissions to the AEMC's Review of the Operation of Retailer Reliability Obligation, the ASX also noted that the MLO plays a useful role in supporting price discovery in regions with low levels of liquidity.[254]

Several submissions to the initial consultation noted that the current MLO framework does not adequately address participants' emerging forward risk management needs.[255] Stakeholders such as AFMA suggested the MLO should be replaced with an explicit market making framework developed in co-operation with market participants.[256] Iberdrola Australia suggested the MLO be made permanent and be expanded to include more participants, longer periods and more frequent bids with tighter spreads.[257] This view was also supported by the AEC:

[248] A T-3 instrument under the RRO is triggered under an instrument made by the AER three years and three months from the commencement of a reliability gap identified by AEMO. Under the T-3 instrument, obligated entities under the MLO must provide qualifying contracts for liable entities to purchase to help meet their share of the forecast reliability gap. The MLO ceases to operate when a T-1 instrument is triggered, as the RRO requires liable entities to be fully contracted to cover their share of the reliability gap one year in advance of the forecast gap.
[249] AER (2024), Interim market liquidity obligation guidelines.
[250] AER (2025), MLO register February 2025.
[251] National Electricity Rules (2025), 4A.G.19(a and b), accessed 27 November 2025.
[252] AFMA (2025), submission to the Initial NEM Review consultation, p 4.
[253] Submissions to the initial NEM Review consultation from AFMA (p 4) and Australian Energy Council (p 9).
[254] AEMC (2025), Review of the operation of the Retailer Reliability Obligation, p 34.
[255] Submissions to the initial NEM Review consultation from Clean Energy Council (p 12), AGL (p 10) and Shell Energy (p 4).
[256] AFMA (2025), submission to the initial NEM Review consultation, p 4.
[257] Iberdrola (2025) submission to the initial NEM Review consultation, p 10.

> *The AEC believes that the RRO in its current form adds no value and should be repealed and that the market liquidity obligation (MLO) could be replaced by an ongoing market making framework to promote liquidity. Market participants have gained experience of both acting as a market maker in the NEM and the benefits of market making. It is generally accepted that the MLO has boosted liquidity and been a positive for the NEM, with parties who have been obliged to act as market makers confident that they can manage the risks of being a market maker.* **– AEC**[258]

The AEMC's review of the RRO found that liquidity in South Australia has declined since the introduction of the RRO and remained steady in other regions.[259] However, in contrast to the MLO, which only delivers increased liquidity in response to occasional reliability gaps over a narrow time period, a permanent market making obligation framework would be designed to target liquidity, price transparency and accessibility to contracts on an ongoing and consistent basis. The Panel is of the view that this is particularly required through the transition.

Voluntary market making schemes can struggle to deliver liquidity and price transparency during times of market stress. Voluntary market making schemes carry the risk that market makers can withdraw from providing services during periods of high price volatility.[260] They risk providing less certainty to the market that the intended liquidity and price-discovery benefits of market making will be available at times of market stress. This is likely to be especially true as electricity systems become more weather dependent, with greater periods of abundance and scarcity of resources.

Voluntary schemes also do not necessarily guarantee an adequate pool of market makers. As market making is riskier when there are fewer market makers, withdrawal of participants from market making schemes can create a negative feedback loop where a declining number of market makers increases the risk to remaining participants.

The ASX's voluntary market maker scheme applies to baseload electricity futures markets in New South Wales, Victoria, Queensland and South Australia. The requirement under this scheme is similar to that required under the MLO, including exclusions that apply to about a quarter of the available trading sessions in a month.[261] Notably, the New Zealand Electricity Authority replaced a voluntary market making scheme in New Zealand with a scheme involving mandatory market making requirements on the four large gentailers. This followed widespread withdrawal of market making services during a period of market volatility in 2018 (see **Case study: New Zealand market making experience**).

[258] Australian Energy Council (2025), Submission to the Initial NEM Review consultation, p 9.
[259] AEMC (2025), Review of the operation of the Retailer Reliability Obligation, p 34–36.
[260] New Zealand Electricity Authority (2020), Hedge Market Enhancements - Market Making, Consultation paper, p 22.
[261] ASX (2025), Market maker arrangements.

4.7 International experience shows market making can improve liquidity and price discovery

Other jurisdictions have experienced similar liquidity challenges to those faced by the NEM, with the literature outlining that electricity markets often lend themselves to outcomes that are highly concentrated, vertically integrated and subsequently result in low forward liquidity.[262] Market making schemes of various forms are an established design feature of electricity derivatives markets internationally. The Panel has considered the experience of the United Kingdom and New Zealand, in implementing market making schemes. The United Kingdom and New Zealand are comparable liberalised markets with relatively high price caps, and vertically integrated generator-retailer structures.

New Zealand's market making scheme (see **Case study: New Zealand market making experience**) provides a useful model for a potential market making obligation in the NEM and has been effective in improving market liquidity. The New Zealand Electricity Authority is expanding its market making scheme further, with a broad review having commenced in late 2025.[263]

Like New Zealand, the United Kingdom also introduced mandatory market making (see **Case study: United Kingdom market making experience**). Market making in the United Kingdom initially had a positive impact. It was repealed after several gentailers in the market became less vertically integrated. This reduced the need for a market making obligation, with enough trading between market participants for sufficient liquidity without it.

Case study: New Zealand market making experience

Market making has featured in the New Zealand electricity futures market since voluntary arrangements began in 2010 following a ministerial review. After a major gas outage in 2018 led to a widening in bid–offer spreads for key listed contracts and a temporary withdrawal of services, the New Zealand Electricity Authority (the Authority) worked with participants to enhance the voluntary market making arrangements. The regulated bid–offer spread was reduced, contract volumes increased and data provided to the Authority improved transparency.

In 2020 the Authority introduced a regulatory backstop. The backstop requires voluntary market makers (the four large gentailers in the New Zealand market) to provide compulsory market making services if their voluntary performance does not meet a regulated standard. The backstop began as a temporary measure and was made permanent in 2021.

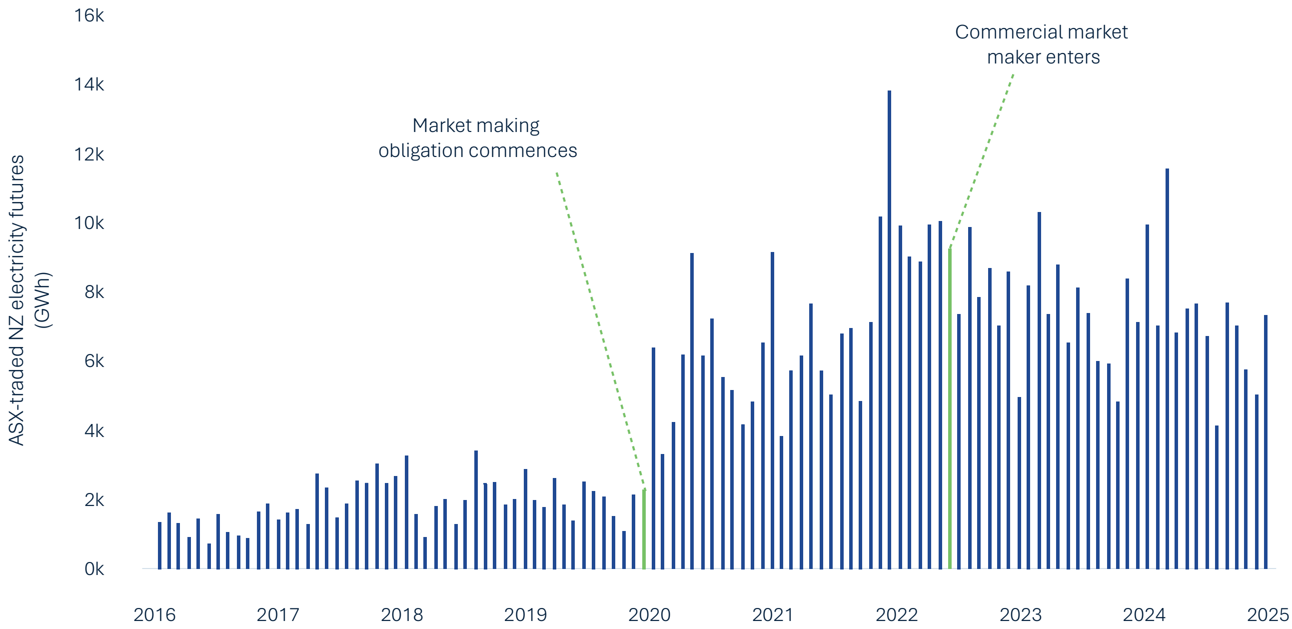
The Authority further reformed the market making scheme with the introduction of a commercial market maker in 2022, which it contracted to provide commercial market making to meet the same service level parameters as regulated market makers (the four large gentailers). The introduction of a commercial market marker aims to enhance the performance and efficiency of the New Zealand electricity futures market while providing the opportunity to increase the diversity of participants. The Authority considers that access to a wider pool of market makers and introducing a potentially more efficient provider will contribute to greater confidence in the

262 T Kanamura and DW Bunn (2022), 'Market making and electricity price formation in Japan', Energy Economics; Cramton (2017), 'Electricity market design', Oxford Review of Economic Policy.
263 New Zealand Electricity Authority (2025), Strengthening price discovery in the forward electricity markets | Our consultations | Our projects | Electricity Authority.

forward price curve. In addition, the commercial scheme will allow participants to give feedback on their desired service levels helping the Authority to adapt the service in a way that strikes an appropriate balance between the costs and benefits. The Authority expects the arrangement should also make the price of market making more transparent and efficient.[264] The costs of the commercial market maker are recovered via a levy on electricity generators and retailers (including existing market makers). The New Zealand Cabinet has provided the Authority with a maximum appropriation of $14.4 million annually, informed by indicative prices for commercial market making obtained in 2021.[265]

Figure 45 shows changes in base quarterly contract volumes traded up to the end of 2024. This is an alternative liquidity measure to open interest and reflects the number of contracts traded in a period.

Figure 45 – Monthly electricity futures traded in New Zealand by volume (2016 to 2024)



Source: ASX data sourced from the New Zealand Electricity Authority (www.emi.ea.govt.nz/r/xihiy), NEM Review analysis.

[264] New Zealand Electricity Authority (2021), Levy consultation: Commercial market-making scheme – Consultation paper, p ii; New Zealand Ministry of Business, Innovation, and Employment (2021), Cabinet paper: Electricity Authority levy increase: funding the commercial market making scheme.

[265] Ibid.

Case study: United Kingdom market making experience

The Office of Gas and Electricity Markets (Ofgem), the United Kingdom energy regulator, introduced a market making obligation in 2014, focusing on the United Kingdom's six major gentailers. Ofgem introduced this obligation as part of its 'Secure and Promote' reforms, which also included minimum service standards for trading and day-ahead reporting requirements. Economic consultants NERA analysed how these reforms affected liquidity. It found that traded volumes increased by 17% from 2013 to 2017, suppliers trebled from December 2013 to June 2019, bid–offer spreads narrowed as the market making obligation specified a maximum spread, and churn broadly remained unchanged.

In November 2019 Ofgem suspended the obligation. After divestments led to reduced vertical integration for four of the six major gentailers, Ofgem removed the market making requirement from their licence conditions.[266] [267] Ofgem considered a market making obligation falling only on two parties would result in costs being disproportionate to the benefits.

Ofgem also considered the obligation had become less effective in enabling robust reference prices relative to what the market would otherwise provide. However, this was likely due to there being fewer regulated market makers and the market becoming more naturally competitive following new entrants and unbundling by previously vertically integrated entities.

Several stakeholders argued against Ofgem suspending its market making obligation. They raised that while the design of the obligation had become obsolete, Ofgem should implement an alternative form of liquidity support instead of suspension.

Consulting on power market liquidity in 2023 to 2024, Ofgem decided not to introduce liquidity interventions in the short to medium term. Ofgem nevertheless committed to continue monitoring liquidity trends and to consider potential policy levers to improve liquidity.

"We are not ruling out the introduction of a market maker in the future and may consider this as a potential option if market conditions show there may be a clear benefit to introducing this."
– Ofgem 2024[268]

Source: NERA 2019, GB wholesale power market liquidity: options assessment; Ofgem 2019, Decision to suspend the Secure and Promote Market Making Obligation with effect on 18 November 2019; Ofgem 2024, Summary of Responses: Power Market Liquidity Call for Input.

266 Ofgem removed obligations for E.ON UK in November 2016, Centrica in August 2018, ScottishPower in January 2019 and RWE Npower in October 2019. EDF Energy and SSE remained.
267 Ofgem (2014), Liquidity in the wholesale electricity market (special condition AA of the electricity generation licence): Guidance, p 8–9.
268 Ofgem (2024), Summary of Responses: Power Market Liquidity Call for Input, p 5.

4.8 A new MMO framework is needed to enhance access to contracts and provide transparent and trusted pricing

A permanent MMO framework in the NEL and NER will become particularly important for managing the risks associated with a weather-dependent system where periods of abundance and scarcity will drive more predictably variable and unpredictably volatile spot pricing outcomes. To provide customers with stable pricing, retailers will need access to transparent, liquid wholesale derivatives markets which facilitate risk management of spot pricing outcomes.

Establishment of a well-designed MMO framework would help to provide market participants with access to a reliable source of contract offerings at a price that is reasonable and fair under all market conditions. The objectives and potential benefits of a MMO framework are outlined in Table 3.

Table 3 – Objectives and impacts of the MMO framework

Core objective	Secondary benefits
Create transparency: Ensure that there is a transparent and trusted price over the short to medium term for financial contracts.	• Higher levels of contracting and risk management should provide **incentives for participants to bid into the spot market more efficiently**. This should help market participants effectively hedge wholesale pricing risk as we move towards an increasingly weather-dependent energy system, with greater periods of abundance and scarcity of resources. • **Promote market entry and competition**, including from non-vertically integrated market participants such as independent generators and retailers delivering benefits to consumers. • A more robust and transparent forward price curve, with prices for bulk energy, shaping and firming consistent over the medium- and long-term timeframes, should **support longer term contracting and investment** together with the proposed ESEM (see **Recommendation 10**). • Higher levels of contracting and risk management for all participants supports **spot market prices reflecting the true supply and demand balance**, which should lead **to better price and reliability outcomes** for electricity consumers.
Boost liquidity: Support short-to-medium-term derivatives market liquidity.	
Improve accessibility: Ensure access for independent generators and retailers to financial contracts on competitive terms to manage **their risk of participating in the spot market.**	

4.9 The Panel recommends energy ministers establish a permanent MMO framework in the NEL and NER, for a small number of key derivative contracts

The Panel has developed an initial set of draft parameters for the detailed design of the proposed MMO framework, as summarised below and detailed at section 3.1 of the **Supplementary Materials**. These parameters cover participant size thresholds, maximum bid–offer spreads, and minimum volume and parcel size requirements. They have been informed by feedback received through consultation on the Draft Report and by input from a targeted MMO Policy Advisory Group established to consult with the Panel on the proposed MMO framework.

How the MMO framework could work – at a glance

1. **Establish the national framework**
   Energy ministers embed a permanent MMO framework in the NEL and the NER. Each minister retains the ability to opt out of the MMO in their jurisdiction.
2. **Define eligible contracts**
   The AER and ESEM Administrator co-convene an industry-led contract co-design process to identify a small set of core derivative contracts for bulk energy, shaping and firming services. The AER designates which of these contracts fall within the MMO, with the ability to add or remove these contracts over time as market conditions evolve. Initially, cap contracts (for firming) and baseload swaps (for combined bulk energy and shaping) would be designated.
3. **Set trigger criteria**
   The AER develops objective liquidity thresholds for each designated contract and NEM region, through consultation with industry (including with the industry-led contracts co-design group). These thresholds determine when the MMO should be activated.
4. **Trigger the MMO**
   The AER monitors liquidity conditions. When liquidity for a designated contract falls below the threshold, the AER triggers the MMO for that contract in the affected region. The relevant energy minister may choose to opt out before activation. Once triggered, the MMO applies until liquidity in that region improves sufficiently.
5. **Apply participation obligations**
   The MMO applies to suppliers of relevant services above a defined size threshold. Obligated participants must maintain minimum trading volumes, comply with maximum bid-offer spreads, and trade via AER-approved exchanges or OTC platforms during the MMO windows. Voluntary market makers, such as energy trading businesses (i.e. non-generation or non-retail trading businesses), may also participate but must adhere to the same bid-offer spreads as obligated participants during the MMO windows.
6. **Monitor, review and evolve**
   The AER periodically reviews the MMO framework concurrently with the review of the long-term Market Price Settings (**Recommendation 5**) and the industry-led contracts co-design group (**Recommendation 7**). Over time, the AER may consider complementary models, such as commercial market making, if liquidity challenges persist.

Stakeholder feedback and engagement on the MMO

Following the release of its Draft Report, the Panel established a MMO Policy Advisory Group to provide input on the design of the MMO. The group was made up of representatives from across electricity generator and retail businesses (both large and small), finance industry businesses, industry bodies, market bodies and governments. The Panel issued a discussion paper to the group on a set of core design questions on an MMO and held two online forums.

The Panel received feedback on both the Draft Report and the MMO discussion paper from stakeholders and members of the Policy Advisory Group. Key themes that emerged from the Panel's consultation process included:

- **Support for a permanent market making framework:** Many stakeholders supported the introduction of a permanent framework with obligations for market making in the NEL and NER, recognising its potential to improve liquidity, price transparency and market accessibility.[269]
- **Different views on the design of a market making framework:** Several stakeholders raised concerns with an obligated framework and supported exploring commercial or voluntary market maker models.[270] Some stakeholders suggested a hybrid approach, combining an MMO with commercial market making, similar to the approach taken in New Zealand.
- **Concerns about costs of obligated market making:** Several stakeholders indicated an obligated market making framework will increase costs and financial risk exposure for obligated participants.[271] Some stakeholders questioned whether an MMO would effectively address liquidity challenges, which they attributed to broader structural issues such as increased variable renewable energy and physical supply constraints.[272] Several submissions argued that liquidity is already sufficient in most NEM regions outside South Australia, and that the MMO should only apply where liquidity falls below a defined threshold.[273]
- **Impact of speculative trading activity.** Some stakeholders raised concerns about the impact of speculative trading activity on obligated market makers and the costs of market making during MMO trading windows. Stakeholders proposed restricting MMO participation to physical traders to avoid these impacts.[274]
- **Implementation of an MMO:** There was broad agreement that the MMO could be phased in (i.e. it could initially apply to existing contracts, then transition to new contracts developed through the co-design process).

[269] Submissions to the NEM Review Draft Report consultation from AEMC (p 3), EUAA (p 6), AER (p 3), Clean Energy Investors Group (p 6), AFMA (p 5), ASX (p 1), Shell (p 4), Hydro Tasmania (p 6), Tesla (p 10), Squadron (p 3), Iberdrola (p 2 and 4), Potentia Energy (p 1), Nexa Advisory (p 10), Flow Power (p 9) and Blue Scope (p 5).

[270] Submissions to the NEM Review Draft Report consultation from Origin (p 2 and 9), ENGIE (p 6), Tilt (p 6–7), AGL (p 9), EnergyAustralia (p 3), Australian Energy Council (p 5), Clean Energy Council (p 7), CS Energy (p 11), Snowy Hydro (p 6), Squadron (p 3), Eku (p 4) and ACEN (p 3).

[271] Submissions to the NEM Review Draft Report consultation from Australian Energy Council (p 5), Alinta (p 6), EnergyAustralia (p 3), Snowy Hydro (p 6), AGL (p 8), Delta (p 2), Tilt (p 6–8), Clean Energy Council (p 7) and ACEN (p 3).

[272] Submissions to the NEM Review Draft Report consultation from Australian Energy Council (p 4), Snowy Hydro (p 5–6) and Alinta (p 6).

[273] Submissions to the NEM Review Draft Report consultation from Origin (p 2), Eku (p 3–4), Akaysha (p 9) and Australian Energy Council (p 5).

[274] Snowy Hydro (2025), submission to the NEM Review Draft Report consultation, p 6.

The Panel's final recommendations seek to balance the competing views of stakeholders on the design of a market making framework. The Panel's recommendation provides for a permanent market making framework in the NEL and NER. However, in response to the views of stakeholders, the Panel recommends that the MMO should be triggered by the AER on contracts and in NEM regions based on pre-determined liquidity thresholds. This amended recommendation reflects the views of some stakeholders that the MMO should only be in place where liquidity is below acceptable levels.

The Panel agrees with stakeholders that current challenges around liquidity are primarily focused in South Australia. However, while liquidity may currently be strong across regions other than South Australia – these regions may experience similar liquidity, transparency and accessibility challenges as the energy transition progresses.

The Panel notes the concerns raised by some stakeholders regarding the costs and risks associated with an MMO.[275] The Panel considers that market participants within the NEM who meet the proposed MMO participation thresholds should have established market trading and risk management functions, with the MMO providing an opportunity to generate value. Overall, the Panel considers that the risks are sufficiently mitigated by the recommended design parameters for the MMO (detailed in section 3.1 of the **Supplementary Materials**), including amendments to:

- Only introduce the MMO immediately in South Australia and only activate the MMO in other NEM regions if an objective liquidity threshold is breached, with ministers retaining an opt-out power.
- Propose a low market share threshold for a physical service provider to qualify as an obligated market maker. This should increase the number and diversity of MMO providers, spreading the risk and benefits.
- Impose small minimum volume requirements for obligated physical market makers, that are proportionate to the size of these providers to limit exposures.
- Introduce specific rules for voluntary market makers. The Panel has recommended three categories of participants relevant to the market making framework. These categories are obligated physical market makers, voluntary market makers (i.e. energy trading businesses) and non-obligated physical participants (e.g. retailers and smaller generators). Under this framework, the Panel has proposed specific rules for voluntary market makers. These businesses will be able to market make and inject liquidity under similar market making terms, including providing a bid–offer spread equivalent to the obligated physical market makers in the region they are trading in.

Taken together, the MMO framework proposed by the Panel would ensure the MMO is a 'tool in the toolbox': enshrined in legislation and able to be applied quickly if liquidity thresholds are breached.

[275] Submissions to the NEM Review Draft Report consultation from Australian Energy Council (p 5), Alinta (p 6), EnergyAustralia (p 3), Snowy Hydro (p 6), AGL (p 8), Delta (p 2), Tilt (p 6–8), Clean Energy Council (p 7) and ACEN (p 3).

4.10 A small set of derivative contracts, determined through an industry-led co-design process, would sit at the core of the MMO

The Panel recommends that the contract types initially designated under the MMO framework be cap contracts for firming services and baseload swaps for combined bulk energy and shaping services. However, the shift to firmed renewables may require a distinctly different set of contracts from those traded today. As such, the Panel recommends that the AER and ESEM Administrator should regularly co-convene an industry-led co-design group to define a small set of core derivative contracts that underpin trading activities and the MMO and ESEM (see **Recommendation 7**). The AER should have the ability to add and remove these contracts as designated MMO contracts over time, subject to market developments and outcomes of the industry-led contract co-design process.

In the second half of 2025 the NEM Review Panel undertook a pilot co-design process to develop contracts for bulk energy, shaping and firming to inform the final recommendations. Further detail on that process, and the recommendations of the co-design pilot working group, are available at section 4.1 of the **Supplementary Materials**. In line with the recommendations of the co-design pilot working group, the Panel recommends the MMO commence with cap contracts in South Australia.

4.11 The market making framework should include mandated participation

While several stakeholders supported voluntary and commercial market making approaches,[276] the Panel has retained its position that an MMO framework should include an element of mandated participation.

Market making schemes range from compulsory participation for designated market participants (e.g. the MLO) to voluntary participation driven by financial incentives (e.g. ASX market making schemes). Participation models may also fall in between. For example, gentailers in New Zealand are voluntary market makers but are subject to performance reporting and have mandatory market making obligations placed on them if they underperform, creating the effect of an obligation. The New Zealand Electricity Authority has also tendered for market making under a commercial arrangement.

Evidence from international examples suggest that voluntary market making tends to be ineffective at times of market stress, which is also when it is most needed to sustain liquidity and a robust forward price curve.[277] As the ASX already currently runs a voluntary market-making scheme, it is not clear that an additional voluntary scheme would add value.

At this stage, the Panel does not recommend a commercial market maker model, where the AER would tender for specialist market-making services, as this would impose additional costs on consumers via a potential cost recovery mechanism. The Panel recommends adopting a mandatory MMO model in the first instance.

The AER may wish to investigate the costs and benefits of a commercial market maker as part of a future review of the MMO. The AER may also decide to deploy a commercial market maker for certain contracts and electricity services where liquidity is low and there are no clear obligated market makers who could provide marketing making for these contracts.

[276] Submissions to NEM Review Draft Report consultation from Origin (p 2), Clean Energy Council (p 7), Australian Energy Council (p 5), Squadron Energy (p 3), Tilt Renewables (p3), Eku (p 4), EnergyAustralia (p 3) and AGL (p 9).
[277] New Zealand Electricity Authority (April 2020), Hedge Market Enhancements Market Making, Ensuring market making arrangements are fit for purpose over time, Consultation paper.

4.12 Market making in different NEM regions should take account of jurisdictional market and policy conditions

The Panel has proposed a structured implementation of the MMO that focuses initially on South Australia, with the ability to extend its application to other regions should liquidity challenges arise and as new contractual products are developed for bulk energy and shaping services through the industry-led contracts co-design process.

Aligning the MMO with the SA Firm Energy Reliability Mechanism (FERM)

The South Australian Department of Energy and Mining is currently developing proposed market making and reliability obligations as part of the FERM.

Under this design, the scheme regulations provide for a market liquidity obligation (SA MLO) applicable to existing and new providers of long duration capacity and a reliability obligation imposed on retailers and other large load customers. Under the SA MLO generators will be required to post bids for a specified amount of nominated capacity in eligible contract markets or on a specified exchange.

The FERM scheme regulations include a head of power for the South Australian Energy Minister to issue a binding guideline governing the market liquidity and reliability obligations. The South Australian Government is currently undertaking work to develop the proposed ministerial guideline.

The NEM Review Panel's **Implementation Roadmap** (section 1 of the **Supplementary Materials**) proposes that further work be undertaken with the South Australian Government to align the SA MLO with the proposed national MMO framework and ensure a coordinated and timely implementation to address liquidity issues in South Australia.

It is important that the design of the MMO framework take account of variations between NEM regions, such as differences in policy settings and the operational environment for hedging. The application of the permanent market making framework across the NEM,[278] will be subject to the designation of contracts and triggering of the MMO by the AER. Under the proposed framework, the Panel recommends that the AER trigger is subject to an opt-out power held by the energy minister in the relevant NEM region.

4.13 The Panel has considered alternative measures to address liquidity and price transparency

The Panel has also considered stronger measures to address liquidity and price transparency in the market, including stakeholder suggestions for accounting separation of vertically integrated gentailers. Stakeholders have suggested that gentailers can divert significant generation capacity within their portfolio away from the derivatives market and towards internal hedging. In its 2024 Wholesale Markets Performance Report the AER highlighted that gentailers have high market shares of firm capacity across the NEM, most notably in New South Wales, Victoria and South Australia.[279] Market

[278] The Panel considers that the framework should also apply in Tasmania. While there is currently no ASX Energy exchange in Tasmania, the Panel notes that it is possible that an MMO could be introduced in the future, subject to market developments in that region and consultation with the Tasmanian Government.

[279] AER (2024), Wholesale Electricity Market Performance Report 2024, p 59–61.

concentration and an ability to allocate firm generation to a gentailer's retail arm through opaque internal accounting raises risks for liquidity and competition in the market.

Stakeholders have suggested accounting separation as a means of driving greater price transparency and suggested the Panel consider this option. Accounting separation requires maintenance of separate accounts between different arms of a business. It ensures costs and revenues can be clearly identified between parts of the business or a related body corporate. Typically, accounting separation includes obligations to report to a regulator, as well as a compliance and enforcement regime to ensure any misallocation of costs and revenues are detected and penalised.

Accounting separation for gentailers would require accounting separation between a business's generation and retail arms. Its objective would be to ensure transfer pricing – the internal price gentailers use to attribute generation to their retail business – is transparent. Obligations on gentailers to report internal transfer pricing to regulators already exist in other electricity markets, such as New Zealand.[280]

The Panel is of the view that an MMO is likely to achieve the price transparency and liquidity required. However, active monitoring of the performance and impacts of its recommended MMO will be necessary to determine whether further measures are needed in the future.

[280] New Zealand Electricity Authority (2021), Internal transfer prices and segmented profitability reporting.

Recommendation 7: The AER and ESEM administrator should regularly convene an industry-led co-design process to define a small set of core derivative contracts that underpin trading activities and the MMO and ESEM

The contracts co-design working group should consist of industry representatives from a range of stakeholder groups, including financial market entities, developers, brokers, generators, retailers and consumers. The Clean Energy Finance Corporation (CEFC) should be a standing participant of the group.[281]

The first formal co-design process should occur as soon as practicable, drawing on the findings from the pilot process conducted by the NEM Review Panel.[282]

The contracts developed through the co-design process:

- should be able to be traded on an exchange platform
- should be able to be the subject of the market making obligations
- should be able to be traded in smaller parcels to reflect the smaller nature of individual generators (e.g. 100 kW rather than 1 MW)
- should be utilised to contract with projects in the ESEM
- could be used in retail price benchmarking.

4.14 A co-design process can accelerate contract innovation and standardisation to meet emerging market needs

Most existing market making schemes have focused on traditional forms of managing forward liquidity – broadly equivalent to baseload swaps and cap contracts in the NEM. As described above, the Panel recommends these products be the starting point for the MMO.

However, to prepare for a firmed renewable energy future (without large centralised thermal units), contract innovation will likely be needed. As described above and in **Chapter 2: Trends and challenges in the NEM**, this innovation process has not been occurring at the pace that the energy transition requires.

To accelerate innovation and resolve coordination failures, the Panel recommends the AER and ESEM Administrator regularly convene an industry-led process to define a small set of core derivative contracts that underpin trading activities and the MMO and ESEM. The participants in this process

[281] This amended recommendation reflects stakeholder feedback that the ESEM Administrator and the Clean Energy Finance Corporation would provide significant commercial expertise for the process (see **Stakeholder perspectives on the contract co-design process**).

[282] The Panel notes that while there is no legislative basis for the process to commence until amendments to the NEL/NER are made, there is no impediment to the AER and interim ESEM Administrator convening the group to ensure it is run concurrently to other reforms in 2026 and its work can be formally adopted once legislation is passed. The Panel recommends governments prioritise resourcing to ensure this occurs, should ministers accept the Panel's recommendations.

would develop a set of derivative contract types that are suitable for managing current and emerging risks, and for use in the MMO and ESEM (**Recommendations 6** and **10**).

The MMO would be able to drive liquidity for the standard set of derivative products over the medium term, and the ESEM would utilise these derivatives to support investment over the long term. In this way, there will be an explicit link between medium- and long-term electricity market economics, built around a common set of industry-developed products.

4.15 Product innovation should be driven by market participants to leverage their expertise

To ensure designated products meet market needs, it is critical the co-design process be strongly industry-led. Informed by the co-design pilot process (see section 4.1 of the **Supplementary Materials**), the Panel recommends:

- The contracts co-design working group should seek to represent the full range of participants in the market while remaining small enough to function effectively.[283]
- Representatives should be experienced commercial staff with the ability to develop proposals in the interest of the sector as a whole.
- Membership should predominantly include natural contract sellers (e.g. generators and standalone developers) and natural contract buyers (retailers and users), or both, covering:
    - A full range of services (firming, shaping, bulk energy); and
    - A range of demand profiles and organisational sizes, including smaller entities or representatives of aggregated entities.
- Contract traders and financiers (bankers, traders, brokers or platforms) should also be included in the group.
- The CEFC should be a standing member of the group as it brings significant investor and financing expertise.

Relevant representative bodies could play a role in convening the process and determining working group membership. Such bodies include AFMA, AEC, Clean Energy Council, Clean Energy Investor Group, Australian Industry Group and Energy Users Association of Australia. Working group membership should ultimately be approved by the AER and ESEM Administrator. The nomination and selection process should be transparent and inclusive to build confidence in the process and its outcomes.[284]

An industry-led co-design process would ensure that expertise held by industry participants actively investing and trading in derivatives markets is leveraged. This will assist in the development of contract types that are well suited to the risk management needs of different participants. It will also allow market sounding with industry participants, as part of the co-design process, to gauge likely trading levels and liquidity after a product is launched. Building market sounding into the co-design process could help inform the pathway to market and implementation timeframe for contract types that are

[283] The NEM Review's pilot process had 13 working group participants, which is probably the maximum membership size the co-design process could accommodate.
[284] Suggested by Clean Energy Investor Group in response to the NEM Review Panel's request for feedback on how co-design membership should be established.

identified through the process. An industry-led co-design process could also assist in identifying additional market benefits. Examples include:

- If parcel size is creating a barrier to access, this process could drive the development of products to be traded in smaller parcels.
- If contract settlement periods (weekly, monthly, quarterly, etc.) are creating market issues, the co-design process could design contract structures using different periods.

In forming this recommendation, the Panel notes that a similar co-design process was successfully used in New Zealand (see **Case study: Utilising the OTC market for New Zealand's super peak contract**, above) and recommended by the ACCC in its 2023 NEM Inquiry.[285]

Stakeholder perspectives on the contract co-design process

Stakeholder feedback received on the Draft Report was strongly supportive of establishing a formal contract co-design process to accelerate the development of standardised derivative contracts. There was broad recognition that without such a process, necessary contract types won't develop through voluntary channels to facilitate a timely transition to a firmed renewables-based power system.

The consensus view emphasised that the success of such a process will depend critically on navigating governance and implementation issues. Stakeholder feedback was primarily centred on these issues:

- Many stakeholders proposed that the AER should not lead the co-design process.[286] Reasons included a perceived lack of financial market knowledge,[287] including of contract market dynamics,[288] limited funding[289] and being too adversarial.[290]
- Conversely, there was strong advocacy for the ESEM Administrator to lead or coordinate the co-design process based on stakeholder perceptions of its relevant capabilities.[291]
- Many submissions emphasised the importance of the process being industry-led.[292]
- AFMA stated that the co-design process "should be flexible enough to evolve to manage the changing needs of the energy market transition without the need for further government action".[293]

The Panel has addressed many of these points in its final recommendation by including the ESEM Administrator as a co-convenor, emphasising a leading role for industry in the process, and retaining significant flexibility in how the process is structured.

[285] ACCC (2023), Inquiry into the National Electricity Market: December 2023 Report, p 11.
[286] Submissions to the NEM Review Draft Report consultation include ACEN Australia (p 2), Australian Energy Council (p 3), AFMA (p 2), CEC (p 9), CEIG (p 8) and CS Energy (p 9).
[287] Submissions to the NEM Review Draft Report consultation from Australian Energy Council (p 3) and AFMA (p 3).
[288] Submissions to the NEM Review Draft Report consultation from CEC (p 9) and CEIG (p 8).
[289] EnergyAustralia (2025) submission to the NEM Review Draft Report consultation, p 3.
[290] ACEN Australia (2025) submission to the NEM Review Draft Report consultation, p 2.
[291] Submissions to the NEM Review Draft Report consultation include ACEN Australia (p 2), Australian Energy Council (p 3), AFMA (p 3) CEC (p 9), CEIG (p 8) and CS Energy (p 10).
[292] Submissions to the NEM Review draft report consultation include Australian Energy Council (p 3), AFMA (p 2), AGL (p 9), ASX (p 2) and EDF Australia (p 21).
[293] AFMA (2025) submission to the NEM Review draft report consultation, p 2.

4.16 The NEM Review Panel piloted the co-design concept to inform this report

In the second half of 2025 the Panel convened an initial co-design pilot process attended by a broad range of industry representatives. Further detail on this process and the recommendations of the industry working group are available at section 4.1 of the **Supplementary Materials**. Industry attendees participating in the pilot co-design process strongly supported the NEM Review Panel's recommendation that a regular, formal co-design process be instituted.

> *The working group believes this pilot has demonstrated the value of an industry-led co-design process and recommends it be adopted as the model for determining contracts to be subject to MMO/ESEM.* **– Pilot Co-Design Working Group**

After considering a range of currently traded and new contract types for use in the MMO and ESEM, the working group agreed a set of suitable contracts subject to finalisation of the operational and definitional characteristics of the contracts being agreed (see **Recommendation 6**, **10**, and section 4.1 of the **Supplementary Materials**).

In addition to agreeing on suitable contract types for the MMO and ESEM, the co-design pilot working group also made observations regarding how the regular co-design process could be conducted in the future (full set in section 4.1 of the **Supplementary Materials**).

> - *Future groups should be given more time to develop their recommendations. Importantly this would allow more time between meetings for participants to absorb proposals and analysis.*
> - *There should be a process for engaging stakeholders outside the working group, potentially by publishing a draft decision for feedback.*
> - *The group agreed that the legislation or rules governing the formal co-design process remain sufficiently flexible to allow the co-design process to be adjusted and calibrated over time.*
>
> **– Pilot Co-Design Working Group** (see section 4.1 of the **Supplementary Materials** for full recommendations)

The Panel supports these observations, in particular ensuring that the AER and ESEM Administrator provide sufficient time and resources for detailed analysis and consideration by the working group in its development of recommendations. The Panel also recommends that guidelines for future co-design processes include the objective that working group decisions be consensus-based, similar to the successful approach taken during the pilot.

The AER was an observer of the pilot co-design process (see section 4.1 of the **Supplementary Materials** for participant details). Learnings and materials from the pilot have been provided to the AER to assist with the timely implementation of the formal process, and can be provided to the ESEM Administrator once determined.

4.17 The AER and ESEM Administrator should convene, but not lead, the formal, regular co-design process

Stakeholder feedback on the Draft Report suggested that, as a regulator, the AER may not be the most appropriate entity to convene the industry-led co-design process (see above). The Panel has pivoted its recommendation so that the ESEM Administrator jointly convenes the co-design process to ensure contracts are suitable for use within the ESEM.

The Panel does not agree that the AER should be excluded from convening the co-design process. Having the AER co-convening this process would build upon its existing experience defining eligible contracts under the MLO and in assessing how derivative contracts are reflected in the calculation of the Default Market Offer.

The AER's expanded wholesale market monitoring functions also reinforce its suitability to play this role. Under these powers, the AER monitors the performance of both electricity contract and spot markets, providing valuable insights to ensure that the co-design process is informed by a comprehensive view of prevailing market conditions.

As the AER assumes responsibility for regulating participants involved in the ESEM and MMO, it will be important for it to continue developing its expertise in contract markets and to help ensure that contract structures evolve in ways that support efficient market outcomes.

To address stakeholder feedback emphasising the importance of an industry-led process, the Panel has refined its recommendation to make clear that the co-design process should be genuinely industry-led, with only administrative support from the AER and ESEM Administrator. This approach aligns with the model adopted for New Zealand's Standardised Flexibility Product Co-design Group, and is similar to the role the AER (as a member of the convening group) played in the pilot process conducted by the NEM Review Panel.

> *It may also be appropriate to look to the approach adopted in New Zealand where a formal Standardised Flexibility Co-Design Group was established by the regulator appointing market participants and platform operators to develop a product for the wholesale market.*
> **– Origin Energy**[294]

[294] Origin Energy (2025) submission to the NEM Review draft report consultation, p 11.

The co-design process should be specified in the NEL and NER, and the AER and ESEM Administrator should specify how the co-design process operates in guidelines. Building on the recommendations of the pilot group (section 4.1 of the **Supplementary Materials**), the NEL, NER and guidelines should include:

- Requirements for the specified contracts to be used in the ESEM and MMO (with appropriate discretion if doing so would be inconsistent with the ESEM or MMO purpose, as applicable, or the contact principles.
- Key elements of the co-design governance model (i.e. selection process for working group members or chair, required stakeholder group representation, process for breaking a tied vote of working group members)
  - The pilot working group also suggested a skilled facilitator should be used to drive forward the co-design process
  - Where agreement cannot be achieved amongst participants, a requirement for the AER and ESEM Administrator to re-commence the process.
- Conditions for initiating supplementary co-design processes beyond standard four-yearly cadence (e.g. a survey of market participants or similar).
- Rules around transparency and reporting to appropriately inform external stakeholders while keeping individual working group contributions anonymous (e.g. Chatham House).
- How legal, technical and secretariat resourcing can be provided to the working group.
- The roles of each participant (see Table 4).

The Panel and pilot working group recommend the laws, rules and guidelines remain sufficiently flexible to allow the co-design process to be adjusted and calibrated over time. Further detail on the recommended role of each entity in the co-design process is provided in Table 4.

Table 4 – Entity roles in the co-design process

<table>
<tr><th>Entity</th><th>Role</th></tr>
<tr><td>1. Industry co-design working group</td><td>• Investigate (including detailed analysis as appropriate) contracts for use in MMO, ESEM, etc.
• Recommend contracts for use in MMO, ESEM, etc.
• Communicate decision-making process and final decision to wider market participants.</td></tr>
<tr><td>2. AER</td><td rowspan="2">• Develop guidelines and Terms of Reference to govern process.
• Trigger co-design process.
• Approve membership of industry working group.
• Provide secretariat support to working group (note taking, room bookings, etc.).
• Approve contracts for use in MMO and ESEM as recommended by working group, OR
• Re-trigger another co-design process if the recommended contracts are found likely to be inconsistent with the ESEM or MMO purpose, as applicable, or the contact principles.</td></tr>
<tr><td>3. ESEM Administrator</td></tr>
<tr><td>4. Industry and consumer representative groups</td><td>• Assist in convening process.
• Assist in determining appropriate membership of industry co-design working group.</td></tr>
</table>

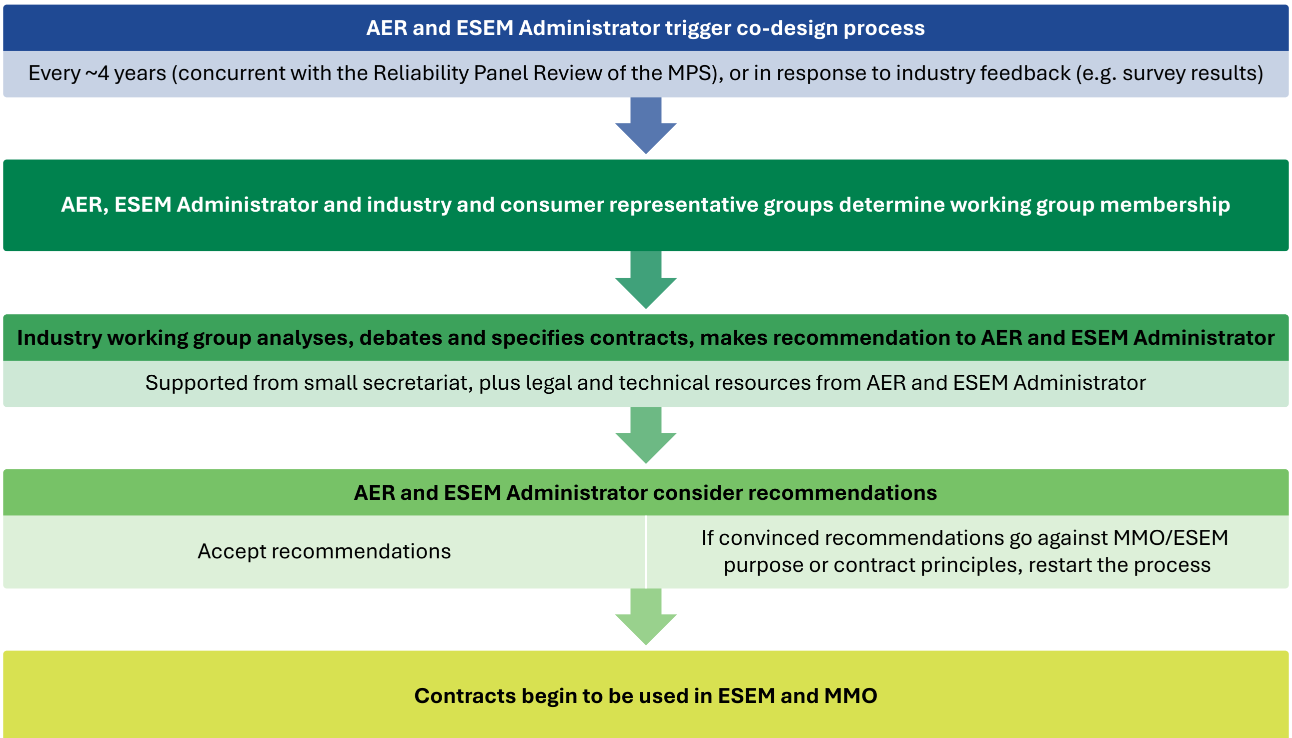
4.18 The first formal co-design process should occur as soon as practicable

An overview of the Panel's suggested approach to implementing the proposed contract co-design process is provided in the **Supplementary Materials (Implementation Roadmap)**.

A co-design process should commence before passage of relevant NEL and NER to allow for prompt implementation of other reforms (namely the ESEM). This could occur with the support of the Energy and Climate Change Ministerial Council, and it is recommended governments support the process with appropriate resourcing.

The duration of this process is intended to extend beyond the 10-week pilot to enable rigorous and extensive technical analysis to underpin the group's deliberations. The process also needs to be appropriately resourced (including legal and technical resources) to allow it to develop detailed contract terms and documentation.

Figure 46 – Contract co-design process overview



4.19 Timing of the regular co-design processes should align with the timing of the Reliability Panel's consideration of market price settings and regular reviews of the MMO

Submissions to the Draft Report suggested that the initially proposed two-yearly process was too frequent.[295] The Panel agrees with this feedback and also notes the co-design process should be informed by the Reliability Panel's latest long-term outlook on the form of the market price settings (see **Recommendation 5**), and regular reviews of the MMO (**Recommendation 6**). A four-yearly cadence, which is currently the timeframe for the Reliability Panel's Reliability Settings and Standards Review, is therefore suggested to ensure market participants remain confident in the durability of the agreed contract design. Section 1 of the **Supplementary Materials** (Implementation Roadmap) provides further details on suggested timings.

Supplemental co-design processes may be required if market participants are of the view that the MMO and/or ESEM contracts no longer remain fit-for-purpose. It is recommended that the AER conduct a regular survey of market participants to determine whether the recommended suite of contracts remains fit-for-purpose.

[295] Submissions to the NEM Review Draft Report consultation from Hydro Tasmania (p 6) and Flow Power (p 9).

Recommendation 8: Energy ministers should commission a review of counterparty risk management and prudential arrangements in the NEM, supported by a multi-agency taskforce and industry subject matter experts

The review should recommend options to improve accessibility and liquidity in derivative markets and increase efficiency of capital deployed as credit support.

4.20 Small, stand-alone retailers are important for competition in the NEM

Through discounted pricing and innovative offers, small and stand-alone retailers provide competitive pressure on retail prices over the long term. Market analysis reflects that smaller retailers (including larger Tier 2 retailers) have a positive market impact by providing competitive offers,[296] using innovation and marketing to attract customers,[297] and having more customers on market offers than their larger counterparts.[298]

Retail markets can only be competitive and efficient if these new, stand-alone retailers can enter the market and acquire risk management services on reasonable terms. To prudently manage risk, both for themselves and on behalf of their customers, electricity retailers need to access derivative markets. This especially holds for stand-alone retailers that do not benefit from owning generation assets.

4.21 Counterparty risk management is key to managing participant credit risk

To trade in the NEM energy-only spot and electricity derivative markets, participants must meet the relevant credit support requirements. Credit support is required to minimise the risk of loss should a participant default on its payments.

Credit support requirements are central to managing counterparty risk and protecting the financial integrity of transactions in the NEM. While the provision of credit support provides confidence to those who have agreed to enter a contract, the Panel has heard that the current requirements can demand substantial working capital and do not always reflect the risk they are designed to manage.

4.22 Collateral costs can disproportionally impact small, new or stand-alone retailers

The current limitations of the framework can impose a significant working capital impact on participants including small, new or stand-alone market participants.

[296] ACCC (2023), Inquiry into the National Electricity Market: December 2023 Report, p 8.
[297] AER (2025), Quarterly retail performance report: October – December 2024, p 16.
[298] AER (2024), Annual retail markets report 2023–24, p 16.

Under AEMO's prudential arrangements, the reallocation of energy and revenue in the NEM's settlement process can reduce a retailer's credit support requirements. However, these arrangements are more straightforward for vertically integrated participants that can effectively enter reallocations between different related entities. Small retailers find it more difficult to access reallocations and when such agreements are reached, stakeholders have advised the Panel that the costs paid by small retailers to transfer spot market exposure can be approximately $3/MWh, thereby increasing the relative cost of small retailers' prudential requirements.

When accessing hedge contracts, small, new or non-vertically integrated retailers can face increased costs and difficulty due to their lack of trading history or lower credit ratings. For exchange traded contracts, the need to fund both initial and ongoing variation margins (that require the holding of additional liquidity to meet margin calls at short notice) can pose a significant working capital burden. Premiums or multipliers applied by Clearing Participants can be opaque and increase in multiples during periods of market volatility. This means that although accessing contracts via a centrally cleared futures exchange enhances market transparency and financial stability, the additional layers of collateral and liquidity requirements can deter or reduce the ability of smaller participants to access exchange traded contracts.

In 2023 the ACCC found that 90% of small retailers stated they were unable to access ASX contracts or faced challenges in executing their hedging strategies.[299] This creates an over-reliance on OTC contracts (see Figure 47), with the ACCC reporting that ASX trades accounted for less than 15% of small retailer-traded contract volumes in 2023. The Panel is concerned that OTC trading in its current form does not provide the price transparency required for participants to have confidence in the market's robustness.

Figure 47 – Proportion of ASX and OTC contracts traded by large and small retailers

Source: ACCC (2023), Inquiry into the National Electricity Market. Note: Excludes power purchase agreements, and load following and generation following shaped products.

[299] Based on compulsory-gathered market participant survey data. ACCC (2023), Inquiry into the National Electricity Market: December 2023 Report, p 7, 95, 98.

Case study: Pressure on derivative market access during the 2022 energy crisis

High and volatile NEM prices in 2022 exacerbated underlying liquidity issues and margining pressures in the energy derivatives market, which limited retailer access to risk management products. Several connected events culminated in the 2022 energy crisis. Higher global energy prices following Russia's invasion of Ukraine drove up east coast gas market prices, which drove up NEM spot prices. A winter cold snap combined with key coal generator outages resulted in AEMO enforcing the $300/MWh administered price cap. AEMO later suspended the NEM and temporarily directed generators to dispatch after some generators elected to not dispatch at the administered price cap.

High and volatile NEM prices during this period put pressure on the energy derivatives market by requiring parties to post more working capital to cover higher margining requirements. As margining requirements do not take physical positions into account, generators who had sold futures contracts had to post large variation margins during this period. While retailers who had already purchased futures contracts would have been on the receiving end of variation margins, generators had fewer incentives to sell during this period and the supply of contracts diminished. Barriers to access increased further as clearing services became restricted during this period. This put pressure on small stand-alone retailers that needed to purchase energy derivatives.

Seven retailers failed during this period, resulting in the AER declaring seven Retailer of Last Resort events.[300] Several retailers cited that they were required to exit the market as they were unable to adequately hedge their forward positions. The AEMC also noted that both high wholesale prices and reduced derivatives market liquidity contributed to a record number of retailer failures.[301]

For OTC derivatives, stakeholders have provided feedback to the Panel that accessibility and credit support requirements can lack transparency and are dependent on the relationship of the two counterparties. OTC credit terms can vary considerably for participants with less creditworthy participants subject to higher contract prices or credit requirements, with threshold limits[302] of exposure often used to determine when any margin posting is required. This can then also limit the number of counterparties available to developers of new generation, as project financing typically requires underwriting OTC contracts with entities that meet credit requirements set by banks.

Despite the above, the flexibility of negotiated OTC credit terms is a strength of bilateral contracting. The Panel understands from stakeholders that smaller or less creditworthy participants are generally able to access OTC contracts in the NEM today.

[300] AER (2022), Retailer failure – RoLR notices.
[301] AEMC (2024), Final report: Review into the arrangements for failed retailers' electricity and gas contracts, p 2.
[302] Threshold limits represent the amount of exposure counterparties are willing to allow before collateral requirements are applied. Threshold limits are calculated as the cumulative mark to market position under which no margining is required.

4.23 Inefficiencies with the existing framework create duplication in working capital required as credit support

All participants are assessed and required to provide credit support separately to AEMO, ASX Clear (Futures) and OTC counterparties. As such, exposures are not automatically netted across markets, even when exposures across positions offset each other. This results in duplication in the amount of capital deployed as credit support and introduces requirements for participants to often hold collateral above the risk they post to the market. Furthermore, except for AEMO's Maximum Credit Limit (MCL) calculations, physical positions are largely ignored. For example, a power station will continue to post collateral for a forward spot position on the ASX Futures that is 'out of the money' despite having a physical asset that will generate against that position in the spot market.

This issue can be further exacerbated during periods of price volatility. For example, when wholesale prices rise, retailers may receive margin calls from AEMO, while Clearing Participants and OTC counterparties may also increase their margin requirements. The inability to reflect hedge positions across different parts of the market can place heightened pressure on working capital liquidity during periods of volatility.

4.24 Stakeholder feedback suggested that counterparty risk management and prudential arrangements require further and specialised consideration

Following release of the Draft Report, the Panel has explored with stakeholders opportunities to improve accessibility of derivative contracts via improvements to counterparty risk management and credit support arrangements. The Panel spoke to and received written feedback from a range of stakeholders including small retailers, generators, peak bodies, market bodies, financial intermediaries and exchange platforms.

Stakeholders expressed strong support for further detailed consideration of this issue but noted the complexity of reforms in this space requires specialised expertise across energy and financial services industries.

Stakeholder feedback on market access and prudential arrangements

Feedback received on the Draft Report was generally supportive of the need to consider in more depth the accessibility of contract markets for small retailers and the efficiency of capital deployed as credit support in the NEM. Key points raised included:

- **Increased costs on small, new or non-vertically integrated retailers:** Stakeholders emphasised that the duplication or inability to net credit support requirements can have a disproportionate impact on smaller participants by tying up a larger share of their working capital.[303]
- **AEMO wholesale market prudentials:** Some stakeholders noted that AEMO's prudential framework may have an easier pathway to reform.[304] Several stakeholders noted the Rule Change to Shorten the Settlement Cycle[305] will have a significant impact in reducing MCL requirements.

[303] Submissions to the NEM Review Draft Report consultation from Flow Power (p 10) and Rainbow Power (paragraph 20).
[304] Submissions to the NEM Review Draft Report consultation from CS Energy (p 9) and AFMA (p 8).
[305] National Electricity Amendment (shortening the settlement cycle) Rule 2024 No.22

- **Risk of changes:** Several stakeholders cautioned that reforms in this space should not be progressed at the expense of the financial integrity of the sector noting that the systemic financial risk of the market should not be increased by any changes to arrangements.[306]
- **Gas market prudentials:** Some stakeholders suggested that any review of prudential arrangements should include consideration of AEMO-operated gas market prudentials and the opportunity to harmonise arrangements across electricity and gas market prudentials.[307]

The Panel has considered submissions to the Draft Report and further targeted stakeholder feedback and recommends that appropriate parties undertake a separate and holistic review of arrangements informed by close consultation with a cross-section of industry participants.

4.25 The Panel recommends a holistic review of counterparty risk management and prudential arrangements be undertaken

Energy ministers should commission a review of counterparty risk management and prudential arrangements in the NEM, supported by a multi-agency taskforce and industry subject matter expertise. The review should be focused on arrangements that require the posting of credit support in the NEM, including the wholesale spot and derivative hedge contract markets. The review should recommend options to improve accessibility and liquidity in derivative markets and increase efficiency of capital deployed as credit support.

The Panel has engaged with stakeholders, including relevant agencies, on the governance and scope of the review. Stakeholders broadly supported further consideration of this issue including ways to better account for physical positions or outstanding payments that are due to generators in credit support requirements. The Panel has incorporated stakeholder feedback on the recommended scope and governance of the review, including the need for recommendations and solutions to be appropriately industry-led.

The Panel notes that reforms in this area are inherently complex as they require consideration of the NEL/NER as well as the *Corporations Act 2001* (including the Financial Stability Standards), and the international Basel Framework. As such, it is important that a multi-agency review utilises expertise from both the energy and financial services sectors. This should include close support and advice from the Commonwealth Treasury, Energy Advisory Panel, Australian Prudential Regulatory Authority and Australian Securities and Investment Commission. The review will also require appropriate and close consultation with industry, regulators and financial intermediaries to develop and test solutions.

The review should be sequenced after the NER amendment to shorten the settlement cycle has been implemented (see the **Supplementary Materials (Implementation Roadmap)**).

306 Submissions to the NEM Review Draft Report consultation from AGL (p 10), AFMA (p 8) and AEMC (p 20).
307 AFMA (2025), submission to the NEM Review Draft Report consultation, p 8. Stakeholders also provided feedback via direct engagement and discussions.

The Panel recommends energy ministers consider including gas market prudential arrangements in the scope of the review. Gas market participants are required to post credit support to AEMO separately for participation in the Declared Wholesale Gas Market, Short Term Trading Market and Gas Supply Hub.

Further detail on the Panel's recommendation is set out in the **Supplementary Materials**, including the suggested structure and governance, reform opportunities for investigation and a draft Terms of Reference for the proposed review.

Recommendation 9: Energy ministers should make a rule change that extends and publishes the generator availability MT PASA projections from three to five years, to support longer-term derivatives market liquidity and price discovery

The Panel believes that providing relevant information to the market over a longer time horizon will improve liquidity and price discovery in contract markets.

The Panel has considered a range of options to improve the availability of market information to support more liquid hedging over a longer period. In **Chapter 3: Ensuring effective operation of the spot market**, the Panel recommends that the Reliability Panel take on an enduring and ongoing responsibility to establish a suitable long-term outlook on the form of the market price settings (**Recommendation 5**). To support longer-term liquidity and price discovery within the derivatives market, the Panel recommends extending the generator availability medium-term projected assessment of system adequacy (MT PASA) projections.

4.26 Extended transparency of supply availability will increase market confidence

Improving liquidity and price discovery over a longer time horizon would be facilitated by extending generation availability projections in the MT PASA, AEMO's forecast of whether the NEM has enough supply to meet demand in the next few years.

In 2020 the AEMC made a rule change to improve transparency of the MT PASA by extending availability projections from two to three years and making them public.[308] This change aimed to reduce information asymmetry, helping market participants make better-informed decisions about investing in new supply, entering contracts and scheduling maintenance. It also intended to increase visibility of reliability risks, giving participants earlier notice of forecast shortages and potentially reducing reliance on emergency reserves and lowering costs.[309]

The quality of these projections is crucial for realising these benefits. The Panel has observed shortcomings in data provided by market participants. For example, participants include few planning outages beyond one year and tend to provide identical availability projections in years two and three. The Panel notes the AER has appropriate powers to monitor and enforce compliance.

The Panel believes that extending the generator availability MT PASA projections to five years should unlock further benefits, despite these early shortcomings, which should lessen as the market adapts. This requirement to provide availability projections would have the effective impact of requiring any plant that is intending to close to notify the market within a five-year window.[310] This would ensure

[308] AEMC (2020), Rule determination Improving transparency and extending duration of MT PASA, p 10.
[309] Ibid.
[310] AEMC (2025), National Electricity Rules, version 227, clause 2.10.1(c2).

that derivative contracts are traded based on the most accurate and up-to-date information. Although projections will always be subject to change, increased transparency is likely to improve market efficiency over time.[311] Extending this information further should increase market participants' confidence over the projection horizon, potentially increasing liquidity in the derivatives market.

Longer-term forecasts of generator availability, and consequently generator closures, would complement the ESEM by enabling market participants to manage uncertainty. This recommendation, in combination with the ESEM, will assist with the issue of entry before exit discussed in **Chapter 5: Unlocking long-term investment in new energy services**.

Stakeholder feedback on extending the generator availability MT PASA projections

Feedback on the Panel's recommendation to extend the generator availability MT PASA projections was received from a range of stakeholders. Support for the recommendation was mixed, with stakeholders (both for and against the reform) highlighting the potential challenges associated with extending the generator availability reporting horizon, including the diminishing reliability of data beyond the current three-year outlook and potential to reduce the accuracy of the forecast.[312]

Some stakeholders suggested also extending the MT PASA's reliability outlook assessment to the same length of time as generator availability data, or to the start of the ESEM. The Panel notes that in the 2020 rule change to improve MT PASA transparency, the AEMC decided against extending the reliability outlook.[313]

The Panel has considered stakeholder feedback and acknowledges the potential challenges in extending the outlook of generation availability. However, the Panel considers these can be mitigated over time and that this recommendation, if implemented, would support greater transparency and outer-year liquidity in derivative markets, providing greater confidence to market participants.

[311] AEMC (2020), Rule determination Improving transparency and extending duration of MT PASA, p 16.
[312] Submissions to the NEM Review Draft Report consultation from Hydro Tasmania (p 27), Delta (p 3), Clean Energy Council (p 8) and EnergyAustralia (p 11).
[313] AEMC (2020), Rule determination Improving transparency and extending duration of MT PASA, p ii.

5

Unlocking long-term investment in new energy services

Chapter summary

The Panel has identified the most significant barrier to investment in new firmed renewable generation in the NEM is the tenor gap – the mismatch between the long financing timeframes required by potential new sellers and the short contracting horizons of market buyers.

This mismatch is not new and has previously been addressed through adjacent policies, such as the Capacity Investment Scheme (CIS), the New South Wales Electricity Infrastructure Roadmap and South Australia's Firm Energy Reliability Mechanism (FERM). However, these long-term investment policies are not fully integrated into the NEM's market structures (spot and derivative markets). Without an enduring framework and clear price signals that align with the lifespan and risk profile of new assets, new projects are unlikely to proceed. This risks higher costs and a less reliable system for consumers.

To incentivise long-term investment in the full range of electricity services needed in the NEM, the Panel recommends establishing the Electricity Services Entry Mechanism (ESEM) – a new scheme which provides a long-term investment signal to address the tenor gap (**Recommendation 10A**). The ESEM should procure new bulk energy, shaping and firming projects by offering fungible, standardised contracts for the 'later years'[314] of a project's life, where buyers and sellers are less able to manage market risk. These contracts would be recycled back into the market at the point in time where buyers will naturally require them to manage the risk of participating in the spot market. The ESEM would allow for long-term investment while enhancing liquidity and connecting long-term investment signals to short- and medium-term markets.

The ESEM should be used to coordinate procurement of Essential System Services (ESS), such as system strength and inertia, where cost-effective (**Recommendation 10B**). It should also apply Australian Energy Regulator (AER)-set market concentration thresholds when determining which projects are eligible to participate in procurement rounds (**Recommendation 10C**) and provide a framework for procuring out-of-market strategic reserves to address low-probability, high-impact events (**Recommendation 10D**).

The Panel also recommends options to ensure regulatory settings, the innovation ecosystem, and existing policies and programs align with the ESEM and continue to facilitate long-term investment effectively (**Recommendation 11**).

Taken together, these recommendations seek to solve the most material issue preventing efficient long-term investment and deliver the services consumers need. The recommendations are designed to address only those issues the market is unlikely to address on its own, complementing and enhancing the operation of the short-term spot and medium-term derivative markets.

[314] 'Later years' in this context is defined as the years of a project's financed life where it cannot find reasonably priced contracts in-market. The Panel anticipates this to be from no less than three years and up to 20 years after commissioning for conventional generation and storage projects, depending on the technical lifespan of the asset. These timeframes will need to be flexible depending upon the service and may evolve over time.

Recommendations

10 Energy ministers should establish an ESEM within the National Electricity Law (NEL) and National Electricity Rules (NER) to facilitate investment in the NEM.

A. Establish in the NEL and NER an ESEM with the following key features:

- The services initially procured through the ESEM should be: bulk zero emissions energy; shaping; and firming.
- The ESEM should allow new electricity service providers to compete for standardised, fungible contracts developed through the industry-led co-design process outlined in **Recommendation 7**. These contracts would offer stable income streams tied to the delivery of defined electricity services, helping providers finance new projects.
- The ESEM should not address risks that market participants are able to manage. The ESEM Administrator should not issue contracts for the years a project is able to secure them in-market. Rather, the ESEM Administrator should issue contracts for the later years of a project's life, allowing electricity service providers to sell their output to retailers or commercial and industrial (C&I) users for the period of time that the market can manage risks effectively.
- The ESEM Administrator should sell the standardised, fungible contracts it has procured back into the market at the point in time that allows retailers and C&I users to manage energy market risk, supporting retail competition.
- The ESEM Administrator should be open to all providers of a given service (bulk energy, shaping, firming), including aggregators of consumer and distributed energy resources (CER and DER), and demand response providers, provided these resources will be scheduled for dispatch by the Australian Energy Market Operator (AEMO).
- The ESEM Administrator should seek to procure quantities of each service that achieve the National Electricity Objective (NEO). This includes any electricity-sector specific requirements of state and territory government emissions policies referenced in the Australian Energy Market Commission's (AEMC's) targets statement.
- Where specific technologies are required to be procured by state and territory government policy and these technologies face greater barriers than the standard tenor gap (e.g. offshore wind, pumped hydro) the ESEM Administrator should use an amended approach to facilitate their procurement.

B. Where cost-effective, projects facilitated through the ESEM should also be able to provide ESS.

C. The ESEM Administrator should apply market concentration thresholds, independently set by the AER, when setting eligibility criteria for participating in ESEM procurement rounds.

D. The ESEM Administrator should facilitate the procurement of strategic reserves covering high-impact, low-likelihood events, with quantities to be procured at the discretion of jurisdictions on advice from the Reliability Panel.

11 Governments and market bodies in the NEM should pursue a coordinated suite of reforms to ensure regulatory settings, the innovation ecosystem, and existing policies and programs are aligned with the ESEM.

A. Governments should clarify how their greenhouse gas emissions targets apply to projects procured to provide firming services, to provide certainty for investors.

B. The Australian Government should task the Australian Renewable Energy Agency (ARENA), in collaboration with the Clean Energy Finance Corporation (CEFC) and other financiers, to accelerate the development and deployment of zero emissions technologies that provide firming at scale.

C. Governments overseeing existing generation underwriting schemes to support long-term investment should consider options to improve derivative market liquidity.

D. The AEMC should review interconnector hedging arrangements to improve long-term certainty. For example, this could include options to the effect of extending the timeframe for inter-regional settlement residue units beyond three years.

E. Once energy ministers are satisfied the ESEM and market making obligation (MMO) are working effectively, they should phase out the Retailer Reliability Obligation (RRO).

F. Once the ESEM framework is established, energy ministers should consider opportunities to rationalise NEM forecasting and planning documents to avoid inconsistencies and duplication.

G. Energy ministers should pursue reforms to improve consistency in the treatment of load, storage and generators connected at the distribution and transmission level, to ensure a level playing field.

12 Jurisdictions should implement this package of reforms expeditiously, ensuring market bodies are suitably resourced to undertake implementation activities concurrently with legislative processes.

Recommendation 10: Energy ministers should establish an ESEM within the National Electricity Law (NEL) and National Electricity Rules (NER) to facilitate investment in the NEM

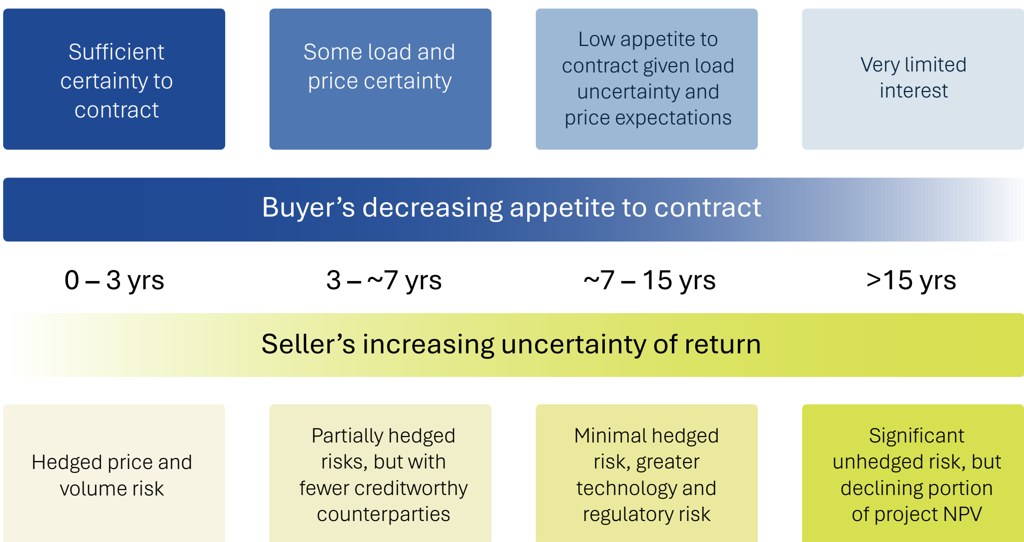
5.1 Long-term investment signals are missing in the NEM

Spot and derivatives markets alone do not deliver long-term signals to support investment in bulk energy, shaping and firming services. Ideally, investors would deliver efficient investment in new supply in response to market prices, and forward prices in derivatives markets would serve as a window to the future, reflecting expectations of spot prices and giving investors the information they need to make informed decisions about building, upgrading or retiring assets.

However, as detailed in **Chapter 2: Trends and challenges in the NEM**, this has rarely occurred in practice, particularly in recent years. Generation in the NEM at its commencement was largely legacy coal-fired plant. Since then, most new generation projects have entered the system partially driven by significant support from policies adjacent to the NEM, such as the Renewable Energy Target among others. Similar challenges are evident internationally and across various market types, including capacity markets. A growing academic and policy consensus now recognises that 'hybrid' market designs that combine strong short-term operational and long-term investment signals are necessary to efficiently deliver the energy transition.[315]

Stakeholders and experts helped the Panel identify barriers to efficient investment. The tenor gap is the most critical of these issues (see Figure 48). Put simply, the timeframes over which investors finance large, fixed cost generation infrastructure do not align with the much shorter timeframes that retailers and C&I users typically use to manage market risk.

Figure 48 – The tenor gap



[315] For example, see ESIG (2025), Electricity Market Visions to support a reliable and affordable grid under electricity decarbonisation, p 29, IEA (2025), Electricity Market Design.

Recommendation 10A: Establish in the NEL and NER an ESEM with the following key features:

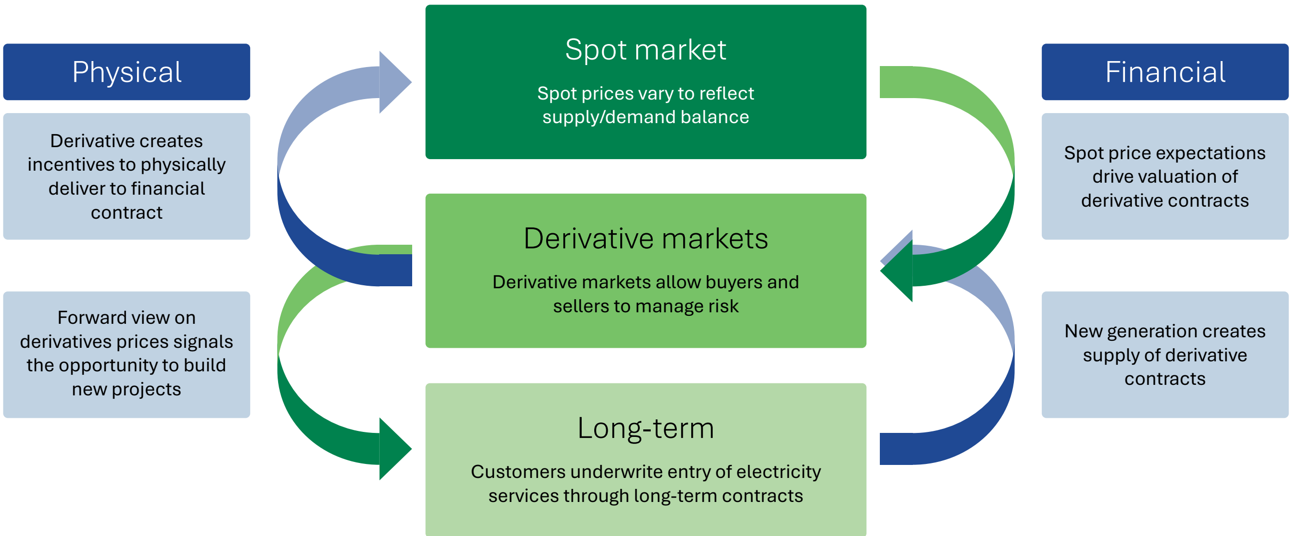
- The services initially procured through the ESEM should be: bulk zero emissions energy; shaping; and firming.
- The ESEM should allow new electricity service providers to compete for standardised, fungible contracts developed through the industry-led co-design process outlined in **Recommendation 7**. These contracts would offer stable income streams tied to the delivery of defined electricity services, helping providers finance new projects.
- The ESEM should not address risks that market participants are able to manage. The ESEM Administrator should not issue contracts for the years a project is able to secure them in-market. Rather, the ESEM Administrator should issue contracts for the later years of a project's life, allowing electricity service providers to sell their output to retailers or C&I users for the period of time that the market can manage risks effectively.
- The ESEM Administrator should sell the standardised, fungible contracts it has procured back into the market at the point in time that allows retailers and C&I users to manage energy market risk, supporting retail competition.
- The ESEM should be open to all providers of a given service (bulk energy, shaping, firming), including aggregators of CER and DER, and demand response providers, provided these resources will be scheduled for dispatch by AEMO.
- The ESEM Administrator should seek to procure quantities of each service that achieve the NEO. This includes any electricity-sector specific requirements of state and territory government emissions policies referenced in the AEMC's targets statement.
- Where specific technologies are required to be procured by state and territory government policy and these technologies face greater barriers than the standard tenor gap (e.g. offshore wind, pumped hydro) the ESEM Administrator should use an amended approach to facilitate their procurement.

The Panel recommends establishing the ESEM to provide the long-term investment signals needed to deliver the new electricity investments that future electricity consumers will require. Importantly, the ESEM Administrator would utilise the same forward market (medium-term) contracts that are used to manage real-time wholesale spot market risks (short-term). This means the ESEM strengthens long-term investment signals without creating a separate or unfamiliar contracting framework.

5.2 The ESEM would create a long-term investment signal for the NEM

The ESEM is intended to provide long-term investment certainty. It achieves this by only addressing the risks the market is clearly incapable of managing. By addressing these risks using the same derivative markets that participants use to manage spot price risks, the ESEM would create an internally consistent link between short-term, medium-term and long-term economic signals (see Figure 49).

Figure 49 – Illustration of how the NEM connects the physical and financial system across three time horizons



The ESEM would support new investment in the core services that retailers and C&I users require by providing long-term contracting for new projects. The ESEM would only be used to procure new bulk energy, shaping and firming services for the timeframes of a project's operation where it is unable to find buyers in the market (i.e. the years after the period in which buyers and sellers can enter into market contracts). In this way, the ESEM Administrator procures new bulk energy, shaping and firming services only where the contracting market is unable to match buyers and sellers.

The ESEM would address the risks of new investment in these later years of a project's life via standardised, fungible financial derivative contracts, co-designed by market participants (see **Recommendation 7**). These contracts would be progressively sold back into the forward derivatives market so that at the relevant time period in the future, retailers and C&I users can manage their future spot market risks in the same way they do today, by purchasing derivative contracts. In practical terms the ESEM would effectively 'warehouse' contracts temporarily until the market requires them. Voluntary participation in ESEM procurement rounds would ensure that project developers who are able to achieve final investment decision with existing in-market contracting options can continue to do so.

The ESEM design is intended to be self-limiting. If market participants move towards solving the tenor gap outside the ESEM architecture, the ESEM would eventually cease to operate.

The ESEM would create an observable long-term contracts market with long-dated forward curves for bulk energy, shaping and firming. This would enable all suppliers and market customers to manage risks over the long term. By focusing only on the later years of new investments, the ESEM should deliver competitively neutral outcomes for all (existing and new) generators as market participants could utilise the same derivative products. Retail competition would be supported through the continued provision of derivative contracts that allow spot market price risk to be managed.

Stakeholder feedback on the ESEM

Submissions to the Draft Report generally expressed support for the ESEM[316], either unconditionally or subject to further design work. Many of those who provided conditional support endorsed the overarching approach and key features, but highlighted that the success of the scheme would depend on the detailed operation, governance and contract design,[317] or suggested that additional policy work and consultation would be required on particular design features.[318]

A small number of submissions did not support the ESEM, as they did not consider the tenor gap represented a market failure[319] or considered the tenor gap was a function of policies to increase variable renewable energy (VRE).[320]

Stakeholders broadly agreed that the tenor gap was a significant barrier to investment in the NEM. The International Energy Agency has subsequently identified the tenor gap as a misalignment experienced in electricity markets internationally.[321]

5.3 The ESEM would leverage existing skills and structures

The ESEM would be an evolution of existing approaches to creating long-term investment signals. It would build on the strengths of existing Australian support schemes by creating a hybrid approach of both decentralised and centralised procurement. This approach would adopt the best parts of existing or forthcoming schemes, including the Renewable Energy Target, the Long-Term Energy Service Agreements (LTESAs) under the New South Wales Electricity Infrastructure Roadmap, the Australian Government's CIS, Victorian Renewable Energy Target auctions, the Australian Capital Territory's renewables auctions and the South Australia Firm Energy Reliability Mechanism.

Some of these schemes could be transitioned to the ESEM over time to provide a consistent framework for investment signals across the NEM.

The ESEM would use the architecture that existing polices have already established, including the skills within contracting bodies (e.g. AusEnergy Services (ASL)) to conduct procurement rounds and enter into long-term contracts, but has several points of difference to make the ESEM more effective and consistent across the short-, medium- and long-term timeframes (see Figure 50).

316 For example, Submissions to the NEM Review Draft Report (2025) from ActewAGL (p 2), APGA (p 3), ATCO (p 1), RayGen (p 2), Woodside (p 3), Snowy Hydro (p 5), DAME Technologies (p 3) and EMX Energy (p 6).
317 For example, Submissions to the NEM Review Draft Report (2025) from Nexa Advisory (p 13), ECA (p 3), CEIG (p 9) and Alinta (p 1–2).
318 For example, Submissions to the NEM Review Draft Report (2025) from AFMA (p 4), Akaysha (p 3), CEC (p 2), EnergyAustralia (p 2) and APA Group (p 4).
319 Monash University, Submission to the NEM Review Draft Report, p 6.
320 The Centre for Independent Studies (2025), Submission to the NEM Review Draft Report, p 5; ENGIE (2025), Submission to the NEM Review Draft Report, p 5.
321 IEA (2025), Electricity Market Design: Building on strengths, addressing gaps, p 68.

Rapid implementation of the ESEM

The Panel recommends that energy ministers implement the ESEM as soon as possible.

A feasible pathway has been identified that would enable the ESEM to commence by FY 2027[322] to minimise any gap following the conclusion of the CIS (see the **Supplementary Materials (Implementation Roadmap)**). This timeframe would require coordinated effort across governments and market bodies, with several workstreams proceeding in parallel (see **Recommendation 12**).

The ESEM represents an evolution from the CIS, FERM and LTESA frameworks and could be implemented relatively quickly by leveraging the expertise and institutional capability within existing market bodies. This is a key design feature adopted by the Panel – using the existing policy and regulatory architecture rather than 'reinventing the wheel'.

To accelerate delivery, interim governance arrangements could be adopted. For example, appointing ASL as an interim ESEM Administrator while enduring arrangements are developed. This could help to provide the market with more immediate certainty and facilitate a more orderly transition.

Figure 50 – The ESEM as evolution, not revolution

		Existing programs	Electricity Services Entry Mechanism
Retains the core features of existing programs ...	**Mechanism**	**Reverse auctions** for competitive investments	
	Anticipated entry trajectory	Anticipated entry trajectory determined by **reliability requirements** and **jurisdictional electricity-sector emissions goals**	
... with tweaks to ensure it is enduring, efficient and market-linked.	**Legal basis**	Legislated by **individual jurisdictions**	Embedded in the **National Electricity Law**
	Contract type	**Bespoke** contracts for the provision of technologies (renewables and storage). Not all programs return contracts to market	**Standardised** contracts for procurement of services (bulk energy, shaping and firming), systematically returned to market
	Period covered	**Entirety** of a project's financed life	**Later years** of a project's financed life
	Risk	For some programs, risks remain with **government**	Risks remain **in-market**

[322] The Implementation Roadmap outlines a pathway that sees a pilot in late 2026 ahead of full commencement in early 2027.

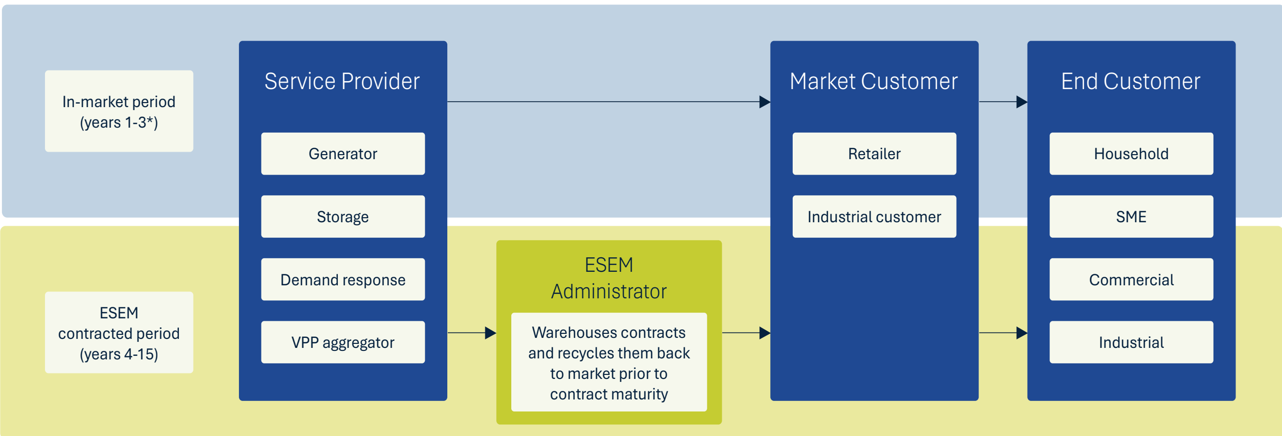
A simple example of how the ESEM would work

With a coal-fired power station scheduled to close,[323] the market will require bulk energy, shaping and firming services to replace it.[324] To meet the NEO (competitively priced, reliable, secure and low-emissions electricity), the appropriate quantity of each service[325] would be procured, through competitive processes that contract the lowest-cost options. New investment would be financed based upon the following:

- Revenue from the early years of the project (for example, years 1 to 3)[326] would be obtained from selling contracts to retailers or C&I users. For example, the firming generation could sell cap contracts or use the generation to hedge sales to a C&I user. Projects would be free to contract as appropriate for these years, with no ESEM involvement.
- Revenue from the later years of the project (for example, years 4 to 15) would be obtained from selling standardised financial derivative contracts to the ESEM Administrator.

As time progresses, the ESEM Administrator would sell equivalent contracts to the market (retailers and C&I users) to create an offsetting position. This would ensure that the bulk energy, shaping and firming services would be available to market participants to manage energy spot market price risk. The long-term investment signal would be effectively integrated into the market, rather than separate or adjacent to it.

Figure 51 – Electricity market contracting with the ESEM



*The ESEM Administrator will have flexibility to set the in-market period, but it should be no less than 3 years.

[323] Sufficient notice would have been provided given **Recommendation 9** to allow all services to be procured and available in time for the coal to close.
[324] Essential system services are also required. These are discussed in **Recommendation 10B**.
[325] The AEMC is required under the National Electricity Law to publish a list of the jurisdictional targets to be considered when applying the national energy objectives, which includes publishing electricity sector specific emissions targets.
[326] The use of three years as an indicative lower bound of project early years is informed by survey data and stakeholder feedback. However, the ultimate timeframe definitions adopted will need to be flexible depending upon the service and may evolve over time.

Cap contracts as a form of capacity payment

In the NEM, cap contracts are commonly bought by retailers and C&I users to manage the risk of high spot prices, and sold by dispatchable generators to secure a stable revenue source. A standard cap contract is likely to be a suitable contract type to incentivise investment in new firming capacity through the ESEM, and as outlined below, can be seen as a form of decentralised capacity payment for dispatchable generators.

Definition

A cap contract gives the buyer the right to receive a payout whenever the spot price exceeds a certain threshold – historically $300/MWh in the NEM – over a defined period (e.g. calendar quarter). The seller of the cap receives a premium (like an insurance payment) and, in return, the seller must pay the difference between the spot price and $300/MWh for each five-minute period when the spot price exceeds $300/MWh.

Example: *A retailer buys a $300 cap contract for 5 MW over Q1 2025. If the spot price stays below $300/MWh, the seller keeps the premium over the quarter. If spot prices jump to $1,000/MWh in one five-minute interval the payout is: ($1,000−$300) × 5 MW × 1/12 hour = $292 (compensating the buyer for the high price paid in the spot market).*

ESEM cap vs capacity payment

The revenue and obligation structures of cap contracts and capacity payments are very similar. Both provide a fixed revenue stream paid over a standard period (i.e. quarterly, annually) and entail an effective obligation to generate in specific circumstances. A cap contract imposes a substantial, market-determined financial obligation to generate when spot prices rise above a pre-determined threshold (e.g. $300/MWh), whereas a capacity payment obligates generation when reserves are tight. In the context of caps procured through the ESEM, an additional obligation to build the physical plant is imposed.

Figure 52 – How the ESEM solves the tenor gap

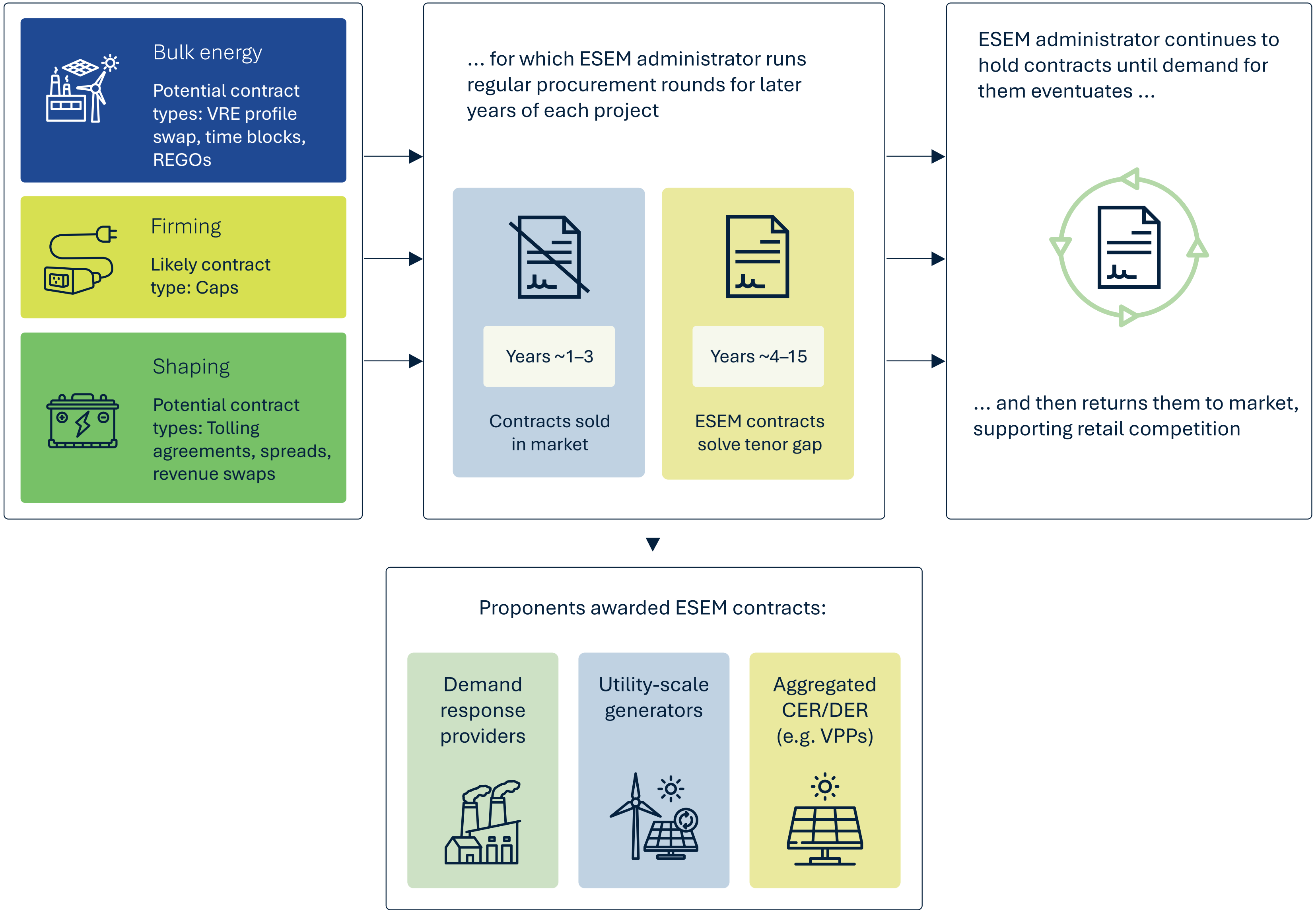


Figure 53 – Key features of the ESEM

Voluntary

The ESEM should be a **voluntary** mechanism – developers will be free to continue with new investments outside of the ESEM which will contribute towards meeting the anticipated entry trajectory.

Enduring

The ESEM should be implemented through the National Electricity Law and National Electricity Rules to make it an **enduring and integrated feature** of the market.

Self-limiting

The ESEM should be **self-limiting**, with feedback loops that allow it to ramp down if markets step in to meet the anticipated entry trajectory.

Linked to jurisdictional targets

The ESEM can allow different **jurisdictions to determine the pace of change** for their region, within a consistent framework aligned to the electricity sector targets in the targets statement[326] that provides certainty to market participants.

Liquidity boosting

By selling fungible, tradeable contracts back to the derivatives market, the ESEM will improve forward market liquidity and allow long-term investment signals to be consistent with medium-term and short-term market outcomes.

Targeted

The ESEM addresses the long term issues the market isn't able to solve due to the tenor gap, but doesn't crowd out market activity where it is working well.

[327] AEMC (2025), Emissions targets statement under the national energy laws, p i.

Why not extend the large-scale renewable energy target (LRET) or CIS?

Several submissions to the initial NEM review consultation paper discussed potentially extending the LRET, creating a certificated capacity scheme similar to the capacity mechanism proposed by the Energy Security Board, or extending the CIS.[328]

While the Panel appreciates the many potential benefits of these schemes, it remains concerned they would not address the tenor gap, which the Panel has identified as the key issue impeding investment in the NEM. Retailers already have obligations (i.e. future electricity demand) that should encourage contracting. It is not clear that additional certificate obligations would meaningfully increase retailer willingness to extend the tenor of contracts, as retailers would face the same uncertainties discussed above and in previous chapters. Regulating retailers and large loads to require 15 years of contracting could theoretically address this issue, but this could simply result in penalties being paid, as retailers could buy certificates in the short term but avoid purchases over a longer timeframe. This would result in a stalemate between buyers and sellers. Penalties would then potentially be paid in later years when the supply of certificates is insufficient. The policy would be ineffective unless the tenor gap is somehow addressed.

The Panel notes that Renewable Electricity Guarantee of Origin (REGO) certificates could be procured through the ESEM to support the bulk energy services. This would be similar to a centrally procured LRET, providing long-term certainty to address the tenor gap. However, this would be one of many different contracting structures that could be used to support a bulk energy service and has not been identified as preferable through the contract co-design pilot.

Importantly, the ESEM Administrator would use a subset of the derivative contract structures determined through the proposed AER and ESEM Administrator-convened industry-led co-design process (see **Recommendation 7** and details at section 4.1 of the **Supplementary Materials**). As existing market participants would use those same contracts, electricity retailers would place similar value on contracts bought from incumbent resources or the ESEM Administrator (to the extent that they both provide similar services to the market). The Panel has not identified material issues suggesting existing market participants are failing to recover the costs of their investments. For this reason, the Panel has developed the ESEM to focus on new projects, not existing projects, but utilising contracts that value the services from new and existing projects in the same way.

Underwriting schemes like the CIS may reduce the liquidity of the medium-term derivatives market (see **Chapter 4: Maintaining liquidity in the derivatives market**). The CIS also addresses risks the Panel believe can be managed in-market – most notably, risks in a project's early years. In other respects, the ESEM builds on many other aspects of the LTESA and CIS frameworks (see Figure 50).

[328] Submissions to the Initial NEM Review consultation advocating for extension of, or establishment of a new scheme similar to, the LRET included AGL, RWE and EnergyAustralia. ACEN Renewables advocated for an extension to the CIS. In submissions to the Draft Report Iberdrola and AEMC suggested extending demand-side obligations to purchase contracts, and the Productivity Commission stated an intention to look at mechanisms complementary to the ESEM such as the Safeguard Mechanism.

5.4 The ESEM Administrator would procure bulk energy, shaping and firming services

The services procured by the scheme would need to reflect the changing needs of the system, as discussed in **Chapter 2: Trends and challenges in the NEM** and **Chapter 3: Ensuring effective operation of the spot market**. The Panel recommends the three core in-market services to be procured at commencement of the ESEM are bulk energy, shaping and firming services, as detailed in Table 5. In combination, these three services underpin retailer risk management for a wide variety of demand profiles or 'load shapes'.

Each service would need a tailored contract structure (or set of contracts) to unlock the ESEM's benefits. The service definitions should be prescribed in the NER, allowing for both the services and the service definitions to evolve over time.

Table 5 – Proposed definitions of services

Name and units	Proposed definition	Examples of provider technologies (not exhaustive)
Bulk energy *Megawatt-hours*	The capability to generate zero emissions electricity from one or more specified generating units or voluntarily scheduled resources.	Utility-scale and rooftop solar, offshore and onshore wind, run-of-river hydro, biomass, concentrated solar thermal.
Shaping *Megawatts of capacity and megawatt-hours of storage or availability*	The capability to consume or generate from one or more specified bidirectional units or voluntarily scheduled resources, or to consume and cease to consume from one or more specified voluntarily scheduled resources.	Utility-scale and small-scale battery storage, pumped hydro, compressed air storage, industrial demand response.
Firming *Megawatts of capacity*	Capacity from one or more specified scheduled generating units, bidirectional units, voluntarily scheduled resources or wholesale demand response units that is capable of being dispatched continuously for the time it takes to reach the cumulative price threshold if prices are at the market price cap.[329]	Pumped hydro, long-duration batteries, compressed air storage, open cycle gas turbines, gas reciprocating engines, hydrogen turbines or engines, industrial demand response, aggregated small-scale storage, concentrated solar thermal.

Ideally, new projects could bid to provide more than one service, where this delivers the most efficient outcome. For example, a pumped hydro project would be well placed to provide both shaping and firming services (and potentially reserves, see **Recommendation 10D**). Alternatively, several projects could aggregate their capabilities and provide a single service where it is most cost-effective to do so.

[329] Currently this duration is around 7.5 hours. It will rise to 8.5 hours on 1 July 2027. For further information, see AEMC (2023), Amendment of the Market Price Cap, Cumulative Price Threshold, and Administered Price Cap, p 2.

Stakeholder feedback on proposed service definitions

Feedback was generally supportive or silent on the proposed definitions of services. Key points raised included:

- **Amending or extending the minimum duration for firming**, with suggestions such as extending the minimum duration that a provider of firming is capable of continuous dispatch,[330] and that the firming definition should be amended to only procure fossil generation as a last resort.[331]
- **Refinement of definitions:** Several submissions called for clearer and tighter service definitions to minimise overlap or ambiguity.[332]
- **Technology neutrality:** Some stakeholders argued that bulk energy services should not be limited to zero-emissions generation, as this may conflict with a technology-agnostic objective.[333]
- **Flexibility:** Others emphasised the need for more adaptable definitions to reflect changing technologies and market needs.[334]

The Panel has considered this feedback and retained the broad positions presented in the Draft Report. However, the Panel has clarified that the service definitions may evolve as technology or other market forces change over time. Importantly, the Panel notes that the contracts co-design process will occur concurrently (and in close collaboration) with the Reliability Panel's provision of a longer-term outlook of the market price settings (**Recommendation 5**). This alignment should provide greater certainty in relation to the definition of firming services. The service definitions should be prescribed in the NER to enable them to evolve to reflect market conditions.

5.5 The ESEM would facilitate a level playing field to ensure least-cost outcomes

The ESEM should allow competition from any technology that can provide the service. While utility-scale generation is likely to be a significant contributor to each service, other resources would be eligible, including:

Aggregated CER/DER	Rooftop solar, home batteries and community batteries
Demand-side participation	Industrial load shifting, commercial buildings, aggregated consumer appliances

A level playing field ensures least-cost outcomes. Allowing all resources to be eligible would maximise the types and numbers of resources that could compete to deliver services, increase scope to drive innovation, and lower costs to consumers.[335] Studies suggest the energy system may benefit from a

[330] For example, submission to the NEM Review Draft Report from ECA (Finncorn Consulting) (p 11), Alinta Energy (p 4) and Origin (p 14).
[331] For example, Justice and Equity Centre (2025), Submission to the NEM Review Draft Report, p 14.
[332] For example, submissions to the NEM Review Draft Report from EnergyAustralia (p 12), AUSTELA (p 3) and Rainbow Power Company (p 11).
[333] For example, Bluescope (2025), Submission to the NEM Review Draft Report, p 11.
[334] For example, Community Power Agency (2025), Submission to the NEM Review Draft Report, p 6.
[335] ESIG (2025), Electricity Market Visions to support a reliable and affordable grid under electricity decarbonisation, p 27.

diverse mix of resources, particularly when it comes to reliability.[336] However, the most efficient mix of resources will be difficult to forecast, especially if technology costs continue to change.[337] As such, a focus on services that is open to the maximum number of competitive resources would increase the likelihood of the ESEM delivering the best outcome for consumers.

The Panel's recommendation at **Recommendation 2B** proposed structured, long-term support to encourage increased participative demand. A level playing field that treats large and small-scale resources, and supply and demand options, on the same footing will allow new demand response resources to compete for ESEM contracts that would serve as structured support for participation.

> *The long-term ESEM contracts could support the investments that enable infrastructure to deliver demand flexibility.* **– Climateworks Centre**[338]
>
> *Crucially, the approach to buying contracts would be technology neutral. Firming auctions would be open to any type of asset capable of being reliably dispatched during time of electricity scarcity including pumped hydro, long-duration storage, gas peaking plants, aggregated small-scale storage and industrial demand response.* **– Productivity Commission**[339]
>
> *The ESEM, designed correctly, offers a possible avenue for Voluntary Scheduled Resource Providers to participate on equal footing with large-scale utility assets.* **– EnergyAustralia**[340]

Stakeholder feedback on establishing a level playing field

Stakeholder feedback reflected widespread support for the Panel's ambition to create a service-based scheme using standard, fungible derivative contracts assessed on price.[341] Some stakeholders highlighted specific considerations the Panel should take into account to give effect to this ambition. This included highlighting:

- **The importance of the contract co-design process:** Some stakeholder responses highlighted the importance of the contract design process in unlocking this service-based vision, noting the risk that the choice of contract type could indirectly advantage one resource over others depending on the design chosen.[342]
- **Simple and transparent assessment process:** Some stakeholders noted the benefits of avoiding complex merit criteria[343] and assessing on the basis of price only.[344]
- **Considering the role of demand response providers:** Some stakeholders raised concerns that the design (focused on addressing the tenor gap) was less well suited for aggregated

[336] For example, IHS Energy (2014), The Value of US Power Supply Diversity, Billimoria et al. (2025), Hedging and tail risk in electricity markets.
[337] Ghadim et al. (2025), 'Are we too pessimistic? Cost projections for solar photovoltaics, wind power, and batteries are over-estimating actual costs globally', in Applied Energy.
[338] Climateworks Centre (2025), Submission to the NEM Review Draft Report consultation, p 10.
[339] Productivity Commission (2025), Submission to NEM Review Draft Report consultation, p 4.
[340] EnergyAustralia (2025), Submission to the NEM Review Draft Report consultation, p 6.
[341] For example, Submission to the NEM Review Draft Report consultation from Bluescope, EDF, EnergyAustralia, HydroTas, Tesla and AGL.
[342] For example, submissions to the NEM Review Draft Report from Origin (p 14) and EnergyAustralia (p 13).
[343] For example, Origin (2025), Submission to the NEM Review Draft Report, p 14.
[344] For example, Bluescope (2025), Submission to the NEM Review Draft Report, p 11, 13.

consumer or demand-side resources, and that demand-side resources would struggle to compete on an equal footing for ESEM contracts.[345]

The Panel has considered this feedback and has outlined a detailed design in the Implementation Roadmap that is immediately workable, while retaining the flexibility to evolve over time to ensure it remains technologically-neutral (see the **Supplementary Materials**). The Panel ensured a range of supply- and demand-side technologies were represented through the pilot contracts co-design process, and recommends this inclusive approach be a permanent feature of the industry-led co-design process to ensure contracts are suitable for a broad range of technologies (see **Recommendation 7**).

5.6 The ESEM focuses on managing risk in the later years of a project's life

The Panel's recommendation for the ESEM to focus on financial derivative contracting for the later years of a project's life is similar to the Australian Competition and Consumer Commission's (ACCC's) recommendation in its 2018 Retail Electricity Price Inquiry. The ACCC had suggested government-supported "energy offtake agreements for the later years (say 6-15)" to bolster NEM investment signals.[346] The mismatch of investors' preference for long-term contracts and buyers' preference for shorter contracts was a consistent theme heard from many stakeholders.

> *[Derivative] markets work in the short term but hard to strike long term contracts – tenor is a key issue.* **– Clean Energy Council (CEC)**[347]
>
> *ActewAGL supports the idea that these contracts can be warehoused and gradually sold back into the market, which is a practical and innovative way to bridge the gap between short-term demand and long-term investment needs.* **– ActewAGL**[348]

[345] FlowPower (2025), Submission to the NEM Review Draft Report, p. 12.
[346] ACCC (2018), Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry – Final Report, p 100.
[347] CEC (2025), Submission to the Initial NEM Review consultation, p 4.
[348] ActewAGL (2025), Submission to the NEM Review Draft Report, p 2.

Stakeholder feedback on the proposed focus on later years and length of the in-market period

While feedback generally supported the focus on later years of a project's life, the Panel consistently heard that the length of the in-market period suggested in the Draft Report was too long, and that the in-market period should be relatively short or more flexible to better reflect current market conditions. Key suggestions included:

- **Flexible timeframes:** Stakeholders proposed allowing adaptable contract durations to reflect the varied lead times and characteristics of different projects.[349]
- **Service-specific in-market periods:** Some submissions recommended varying lengths of in-market period for different services.[350]
- **Short in-market period:** Others suggested a short in-market period to better align with perceived project realities.[351]

Some stakeholders suggested there would remain a revenue gap inhibiting investment in zero emissions bulk energy.[352]

The Panel maintains its position that it should be the ESEM Administrator's responsibility to determine the appropriate in-market period for each service based on prevailing market conditions. As a starting point, the Panel envisages this may be as short as three years in the early years of the ESEM, reflecting continued presence of legacy plant, and then lengthen as large incumbent units retire in the relevant region. The ESEM Administrator should also have discretion over the contract timeframes and length, but these need to be uniform for each service in each region to ensure simple comparison of bids and decision-making. The ESEM Administrator should set the required in-market period as far forward as market conditions reasonably allow, with a minimum of three years for core services.

For 'special tenders' aligned with jurisdictional technology-specific targets, particularly for technologies facing barriers beyond the tenor gap (e.g. pumped hydro, offshore wind), the in-market period may be reduced, recognising these additional barriers.

5.7 The ESEM Administrator would procure quantities of each service guided by the NEO

The NEO should form the basis for determining the quantities of each service that are anticipated to be needed. The NEO is intended to capture the long-term interests of consumers through several limbs, including:

1. **Reliability and security:** The ESEM Administrator would procure sufficient new electricity services to meet demand and keep the electricity system reliable, including coordination of ESS (see **Recommendation 10B**).

[349] Fluence (2025), Submission to the NEM Review Draft Report, p 12.
[350] Squadron Energy (2025), Submission to the NEM Review Draft Report, p 7.
[351] For example, Origin (2025), Submission to the NEM Review Draft Report, p 15.
[352] For example, AEMC (2025), Submissions to the NEM Review Draft Report, p 1.

2. **Price (i.e. allocative efficiency):** The ESEM Administrator would procure new electricity services competitively, at the lowest possible cost to consumers as reflected by the forward price curves published by the ESEM Administrator for bulk energy, shaping and firming.[353]
3. **Achievement of targets for reducing Australia's greenhouse gas emissions:** The ESEM would procure new electricity services to meet any electricity-sector state and territory targets to reduce Australia's greenhouse gas emissions as outlined in the AEMC targets statement.[354] The ESEM Administrator would not consider economy-wide greenhouse gas emissions targets as these would require subjective interpretation about the appropriate share of emissions reductions in the electricity sector. Australian emissions targets as adopted by the Commonwealth Government would be considered to the extent individual jurisdictions specify in the AEMC targets statement that a national target (or relevant share) is to apply in their jurisdiction.

Treatment of inconsistent or conflicting jurisdictional targets

Where the ESEM Administrator identifies that jurisdictional targets may be inconsistent with each other, it should engage with the relevant governments to seek resolution. To be clear, state and territory jurisdictional targets are only likely to be inconsistent in a limited set of circumstances. For instance, inconsistency could arise where one jurisdiction has a target that requires it to be a net exporter, while its neighbouring jurisdiction has a target that requires it to meet most of its consumption with energy generated within its own region.

In such cases, the ESEM Administrator would provide advice to the relevant jurisdictions outlining the nature of the inconsistency and share the latest information on regional pricing to support decision-making. The jurisdictions would then seek to reach agreement on an appropriate pathway forward, which may involve adjustments to targets or the adoption of an alternative interpretation. If agreement cannot be reached, the ESEM Administrator should proceed with in-region procurement to meet each jurisdiction's targets as originally specified.

A key design feature of the recommended ESEM is its hybrid nature: it would rely upon markets for the observable future and only intervene for the later years of project lifespans. This would create an 'automatic stabiliser' effect for quantities to be procured. If the ESEM Administrator procured too much, observable contract prices would be too low to support new investment and ESEM procurement rounds would either be unnecessary or fail to attract economic projects. This approach would help prevent over-procurement based on long-term projections that may not align with market realities.

The ESEM Administrator's long-term contracting would be guided by the quantity and mix of technologies and pricing for the various services being put forward to meet the short-term market needs. In this way, market participants and the ESEM Administrator would have an implicit 'meeting of the minds' about the appropriate mix of services to best deliver the least-cost outcome of keeping the system secure, reliable and moving towards net zero emissions.

[353] The forward curves would be the aggregated weighted average of prices for each contract (firming, shaping and bulk energy) in each vintage (e.g. month, quarter, year).
[354] AEMC (2025), Targets statement for greenhouse gas emissions.

Any forecasts used to determine the anticipated entry trajectory should offer opportunities for stakeholder engagement, be transparent, and be subject to rigorous review to improve forecast accuracy over time, akin to AEMO's existing forecasting processes. The Panel does not anticipate that the ESEM Administrator would publish specific quantities to be procured. Instead, it would publish forecasts of existing and committed supply and anticipated demand for each service. The projected long-term shortfalls would be clear to all stakeholders without prescribing procurement volumes in advance.

The ESEM Administrator would then seek to procure resources to meet this anticipated entry trajectory, accounting for resources built outside the ESEM. Through the use of published forward price curves for each service and the in-market requirement for each service, the ESEM Administrator will be well placed to allow the market to guide investment in the most efficient mix of services with its role largely to overcome the tenor gap for the most efficient projects. The ESEM Administrator should consult each jurisdiction on its draft forecast to provide an opportunity for comment on whether it has interpreted the jurisdictional targets in the AEMC's targets statement correctly. Jurisdictional consultation would be limited to ensuring these targets have been interpreted correctly.

> *It is important that the ESEM target-setting process is transparent, systematic, and based on a codified process. This will help prevent ad-hoc interventions which risk undermining investment certainty, market efficiency, and the "automatic stabiliser effect" envisaged in the draft report.*
> **– Alinta Energy**[355]
>
> *Australia does a better job than many other countries in its energy system planning, so we urge the planners to take advantage of work already undertaken... The wheel does not need to be re-invented here, just take advantage of the existing processes, coordinate between them, and ensure iterative improvement of them through feedback cycle.* **– RWE Renewables**[356]
>
> *The asymmetrical risk of under-procurement vs over-procurement given excess capacity would naturally drive the price of ESEM contracts and wholesale energy prices down as a self-correcting mechanism. However, a credible, methodical, and transparent capacity planning tool will be critical to ensure scheme success and should build on the detailed and consultative work of the AEMO ESOO and ISP work streams.* **– Tesla**[357]

Stakeholder feedback on determining quantity and timing of each service procured through the ESEM

Stakeholders expressed strong interest, both through formal submissions and direct engagement with the Panel, in how procurement quantities would be set and iterated over time. Key points raised included:

- **The need for a rigorous and transparent methodology:** Many stakeholders called for a robust, independent and transparent approach to setting procurement trajectories to

[355] Alinta Energy (2025), Submission to the NEM Review Draft Report, p 4.
[356] RWE Renewables (2025), Submission to the NEM Review Draft Report, p 2.
[357] Tesla (2025), Submission to the NEM Review Draft Report, p 12.

mitigate against the risk of over-procurement, with broad support for using the NEO to guide these trajectories.[358]

- **The benefits of leveraging existing forecasting tools:** Several submissions recommended using existing forecasting products, such as the Integrated System Plan (ISP), to inform the anticipated entry trajectory rather than developing entirely new methodologies. For example, AEMO and RWE noted that Australia already has strong planning frameworks and urged the Panel to build on these rather than 'reinvent the wheel'.

The Panel has considered this feedback, which supports its view to require a robust and transparent approach to setting the anticipated entry trajectory. The Panel proposes that the methodology for establishing the anticipated entry trajectory be developed by the ESEM Administrator in consultation with stakeholders, with the process and transparency requirements to be included in the NEL, NER and guidelines architecture. A suggested approach to trajectory-setting is outlined in the detailed design paper (see section 6.2 of the **Supplementary Materials**).

Figure 54 – Factors informing anticipated entry trajectories

The anticipated entry trajectory would be guided by services needed to:

Meet the reliability standard at least cost to consumers	**Meet state and territory electricity-specific emissions reduction targets**

having regard to:

Existing, withdrawing, & committed services and **announced closures** of existing plant, including plant committed outside the ESEM, across both demand- and supply-side providers.	**Market 'look-forward':** Comparing offers received under ESEM tenders with long-run marginal cost and prevailing market contract prices.	**Market 'look-back':** Reviewing recycling prices received versus amounts paid, and comparing these to long-run marginal cost benchmarks.

[358] For example, Submissions to the NEM Review Draft Report from the AEC (p 2), Alinta Energy (p 4) and AGL (p 11).

5.8 Where jurisdictions have technology-specific targets, the ESEM would be capable of supporting technologies that face barriers beyond the tenor gap

While reform efforts should continue to promote consistency and harmonisation across the NEM, individual jurisdictions remain free to pursue their own policy objectives within this shared framework. Where states and territories have specific technology-focused goals for the deployment of new energy services, and these targets are included in the AEMC targets statement,[359] the ESEM should facilitate investment aligned with them.

The ESEM Administrator would be empowered to run special tenders as needed to support the implementation of technology-specific targets set by jurisdictions, as reflected in the AEMC targets statement. While the ESEM Administrator would have flexibility to design tender processes and contract structures as needed to support the specific technology being pursued, the adjustments should be minimised insofar as it is possible to preserve the benefits of simple, price-based competitive processes (see section 6.1 of the **Supplementary Materials** for further detail).

Technologies that face barriers beyond the tenor gap

The ESEM Administrator would be required to procure resources consistent with state and territory electricity sector emissions targets in the AEMC targets statement.

Some specific technologies that form the basis of jurisdictional electricity sector emissions targets and face barriers greater than just the tenor gap could be supported by the ESEM. In particular, the deployment of offshore wind and long-duration storage (including pumped hydro resources) could be integrated within the ESEM architecture.[360] Other resources, such as innovative long-duration storage, could also be included over time if jurisdictions mandated them.

Offshore wind offers several benefits to the energy system, including higher capacity factors and generation that may be non-correlated with other weather-dependent resources (higher value bulk energy). Similarly, pumped hydro can provide synchronous generation services to support grid security (ESS) and very-long-duration storage (firming, shaping and reserves).

However, investments in these projects might face higher costs or additional risks compared to other providers of the services to be procured through the ESEM. To the extent that technologies face these barriers beyond the tenor gap, the Panel notes that projects would still be required to source the most competitive contracts for their service from the market, and that additional costs beyond what the market is prepared to pay for the service could be recovered from consumers via the same cost recovery mechanism established for the ESEM, but for the life of the entire project (e.g. years 1 through 25).

Economic analysis and long-lived infrastructure assets: A roundtable was held by the International Hydro Association to allow the Panel to better understand the issues related to pumped hydro economics. The Panel notes that conventional economic analysis is not well suited to considering the benefits of very long-lived infrastructure as these are effectively

[359] AEMC (2025), Targets statement for greenhouse gas emissions, p 1.
[360] For example, see Victoria Offshore wind energy, NSW Pumped Hydro Roadmap, Hydro Tasmania, Queensland Hydro.

discounted to zero beyond a few decades. The Panel considers that it would be inappropriate for the ESEM Administrator to develop a non-standard approach to economic analysis of long-lived infrastructure. As such, the Panel recommends that governments carefully consider the costs and long-term benefits of pumped hydro (and other longer-lived infrastructure assets). Where governments view that these assets provide intergenerational benefits that outweigh the upfront costs, they should include these assets as part of their explicit policy frameworks. This will then be adopted in the AEMC targets statement and the ESEM Administrator will be well placed to procure the services at least cost.

Treatment of pre-existing policy commitments: Where jurisdictions have already made policy commitments to investors in relation to the form of contracting to be used for technology-specific procurement prior to ECMC consideration of the NEM Review's Final Report, the Panel recommends that a separate approach be adopted. The ESEM Administrator would, at the request of the jurisdiction, shorten the in-market period to zero and require a particular contract to be utilised. This would facilitate investor confidence and allow existing technology-specific processes to be seamlessly integrated into the ESEM architecture.

5.9 The ESEM would assist with orderly exit, consistent with the pace of change determined by governments

The orderly exit of large coal generators is a critical part of the transition and a source of uncertainty for market participants, as discussed in **Chapter 2: Trends and challenges in the NEM**. The ESEM would indirectly facilitate the orderly exit of these generators.

As noted earlier, the AEMC targets statement[361] sets out the electricity-sector emissions reduction targets the ESEM would be required to deliver, consistent with the NEO, if established within the NEL. Energy ministers determine their electricity sector specific emissions targets. The AEMC targets statement is simply the means of embedding these so they are applicable under the NEO.[362] The ESEM Administrator would procure sufficient new services to allow coal or other emissions-intensive generators to close while meeting consumers' reliability needs. For example, Victoria's existing targets would require the ESEM Administrator to procure sufficient renewables to meet 95% of generation, 6.3GW of storage and 4GW of offshore wind by 2035.

The ESEM should be used to ensure the purpose of the Orderly Exit Management Framework for coal and gas generation exits is achieved.[363] When considering anticipated entry trajectories, the ESEM should, at a minimum, align new entry with retirement dates for large thermal generators[364] to ensure sufficient replacement resources are procured and available prior to the large generation units ceasing operation. The ESEM could do this in a way which seeks to achieve some overlap (to ensure continuity of system reliability and security) but with the objective of minimising this overlap and any impact on wholesale prices. To give jurisdictions confidence that projects are delivered on time, it will be important for the ESEM to ensure appropriate incentives for commissioning timeframes are to be met, through the combination of market signals and ESEM contracts.

361 AEMC (2025), Emissions targets statement under the national energy laws.
362 SA Government (2025), National Electricity (South Australia) Act 1996.
363 DCCEEW (2024), Orderly Exit Management Framework.
364 The Panel is also proposing generators be required to provide MTPASA information out to five years, which would give the ESEM Administrator up to five years lead time to address any shortfall associated with closing thermal generators (see **Recommendation 9**).

> *The ESEM will only deliver efficient quantities and prices if its tender schedule is explicitly tied to timely coal retirements, given uncertainty around coal exits is one of the key risks facing renewable energy developers today.* **– Nexa Advisory**[365]
>
> *Our primary concern is the lack of clear market signals for the closure of coal and the ongoing reliance on underwriting new entrant capacity rather than creating enduring, demand-side market signals for investment. Governments will naturally (and rightly) continue to want to see investment in new capacity ahead of coal closures. However, recent evidence suggests investors can have little certainty of announced coal closure dates (which may be earlier or later than anticipated). As such, until the majority of coal stations have closed, it is credible that near-term prices (e.g., years 1–7) will not be sufficient to justify investment.* **– Iberdrola**[366]
>
> *The lack of certainty around coal closure timing remains a fundamental challenge. CEIG stresses that although long-term contract pricing will remain linked to spot market signals, without a credible coal closure schedule, defining long-term pricing will be difficult.*
> **– Clean Energy Investor Group (CEIG)**[367]
>
> *The Panel should consider starting support through the [ESEM] in the earlier years of project life, given the coal exit uncertainty currently faced, then paring it back over time to only cover a project's later years of life. The Panel should consider further means to reduce uncertainty around coal exits, including potential integration of coal exit timing with strategic reserves and/or the ESEM, to improve investor confidence and the market's ability to deliver stable long-term price signals.* **– Institute for Energy Economics and Financial Analysis (IEEFA)**[368]

5.10 ESEM contracts would be standardised and fungible

The Panel has noted through consultation that there is a range of derivative contracts currently used by buyers and sellers of bulk energy, shaping and firming to manage risk. As detailed in **Chapter 4: Maintaining liquidity in the derivatives market**, these contracts will need to evolve to allow market participants to manage risks and hedge their revenue and costs as the energy transition continues. The contracts used by the ESEM Administrator should help to promote these innovation efforts. In this context, the Panel has recommended that the AER and the ESEM Administrator facilitate a regular industry-led co-design process for contracts used in both the MMO and the ESEM (see **Recommendation 7**).

365 Nexa Advisory (2025), Submission to the NEM Review Draft Report consultation, p 15.
366 Iberdrola Australia (2025), Submission to the NEM Review Draft Report consultation, p 3.
367 CEIG (2025), Submission to the NEM Review Draft Report consultation, p 8.
368 IEEFA (2025), Submission to the NEM Review Draft Report consultation, p 1–2.

Contract recommendations from the contracts co-design pilot

In the second half of 2025 the NEM Review facilitated a contracts co-design pilot working group with market participants from across industry. The working group considered a range of potential contract types and ultimately agreed that a workable set of contracts exists that could both function to support entry through the ESEM and the Panel's proposed MMO.

For the services to be procured through the ESEM, the working group agreed that caps are the preferred contract to support firming services, while an ex-post set of contracts consisting of dispatch-weighted average swaps and heads and tails spreads were agreed as the preferred contracts for bulk energy and shaping respectively. The agreement on ESEM bulk energy and shaping contracts was subject to further investigation of how these contracts are operationalised and financed, with time-of-day-products also noted as a workable alternative.

Refer to section 4.1 of the **Supplementary Materials** for a more detailed account of the pilot working group's recommendations and an overview of the proposed ESEM contracts.

The Panel recommends that the derivative contract structures be developed through the industry-led contracts co-design process (see **Recommendation 7**). Important guiding principles for the nature of the derivatives should be established in the ESEM's regulatory architecture, including that the derivative contracts should:

- Be designed to manage medium- to long-term financial risks that the market is unable to address (i.e. systemic risks which lead to the tenor gap) and support investment under the ESEM.
- Be financial (i.e. not tied to physical plant operation), tradeable, structured to support price transparency and useful for retailers and C&I users for managing exposure to spot prices across the three targeted services.
- Encourage generators to deliver services when they are most needed, aligning incentives with system value and reliability outcomes.

The derivative contracts secured by project developers through ESEM procurement rounds for the later years of a project would be financial in nature but contingent upon plant commissioning. This is necessary to ensure successful project bids would result in the new project being built.

As the ESEM Administrator continues to procure services, it would warehouse contracts until liquidity emerges for it to begin to recycle these derivatives. Management of the derivative position would be governed by a comprehensive risk management framework, strong controls and governance oversight.

Stakeholder feedback on proposed ESEM contracts

While submissions supported the Panel's proposed approach to creating standardised and fungible contracts,[369] other stakeholders emphasised that a one-size-fits-all approach to contract design may not suit the distinct characteristics of each service. Key points raised included:

[369] For example, ASX (2025), Submission to the NEM Review Draft Report consultation, p 2.

- **Flexibility in contract design:** Some submissions suggested developing a broader or more adaptable set of contracts for each service, rather than limiting to a single contract type per service.[370] There was both support[371] and opposition[372] expressed for the idea of ESEM contracts in the form of options.
- **Non-fungible PPAs should be included:** Other stakeholders in noting that fungibility will require volumes to be fixed exposing sellers to shape risk, which may not be suitable for all renewable projects, suggested that non-fungible run-of-plant Power Purchase Agreements (PPA) should form part of the ESEM mix.

The Panel has considered this feedback and maintains its preference for developing a limited set of derivative contracts through the industry-led co-design process. The focus should remain on creating service-based, standardised and fungible contracts that enable the ESEM Administrator to compare bids efficiently and make objective decisions. Including a broad range of project developers covering a wide range of technology types in the enduring industry-led co-design process would ensure ESEM contracts are effective for a broad range of technologies.

Some stakeholders submitted views on possible contract types for use in the respective ESEM procurement rounds for bulk energy, shaping, and firming services in response to the Draft Report. Several stakeholders proposed more than one potential contract type per service.

- **Firming:** A strong majority of stakeholders that put forward a preferred contract to support firming services in the ESEM proposed that cap contracts be adopted.[373]
- **Shaping:** There was less homogeneity in submissions advocating for a particular shaping contract, with the greatest number proposing peak time of day blocks (six).[374] Virtual tolling agreements[375] and heads and tails spreads[376] were proposed by three and two stakeholders respectively.
- **Bulk energy:** Stakeholders had similarly diverse views on potential contracts for use in the proposed ESEM bulk energy procurements. Four advocated for run-of-plant PPAs[377], three for time-of-day blocks or other fixed shape contracts,[378] and two stakeholders advocated for reference variable renewable energy (VRE) profile contracts.[379] There was also some support for the ESEM supporting bulk energy projects through the purchase of REGOs.[380]

[370] For example CEIG (2025), Submission to the NEM Review Draft Report consultation, p 2.
[371] For example, submissions to the NEM Review Draft Report consultation from LDES Council (p 7), Origin Energy (p 16), Rainbow Power Company (p 15) and RWE (p 1).
[372] For example, AEMC (2025), Submission to the NEM Review Draft Report consultation, p 25.
[373] For example, submissions to the NEM Review Draft Report consultation from AGL (p 12), EDF Australia (p 25), Enel X (p 13), EnergyAustralia (p 15), Flow Power (p 12) and Iberdrola (p 6).
[374] For example, submissions to the NEM Review Draft Report consultation from ACEN Australia (p 2), AGL (p 12), CleanCo (p 7), EnergyAustralia (p 15), LDES Council (p 7) and Rainbow Power Company (p 14).
[375] For example, submissions to the NEM Review Draft Report consultation from ACEN Australia (p 2), EDF Australia (p 25) and EnergyAustralia (p 15).
[376] For example, submissions to the NEM Review Draft Report consultation from EDF Australia (p 25) and LDES Council (p 7).
[377] For example, submissions to the NEM Review Draft Report consultation from ACEN Australia (p 2), CEIG (for wind) (p 2), CS Energy (p 12-13) and IEEFA (p 6).
[378] For example, submissions to the NEM Review Draft Report consultation from ACEN Australia (p 2), CEIG (for solar) (p 2) and EnergyAustralia (p 8).
[379] For example, submissions to the NEM Review Draft Report consultation from EDF Australia (p 24) and Iberdrola (p 5).
[380] For example, submissions to the NEM Review Draft Report consultation from AEMC (p 25) and Iberdrola (p 5).

Representatives from several of the organisations that articulated views on potential ESEM contracts in their Draft Report submissions subsequently participated in the pilot contract co-design process convened by the Panel (see **Recommendation 7**). The bulk energy (ex-post dispatch weighted average swaps) and shaping (heads and tails spreads) contracts preferred by the co-design pilot working group evolved from those suggested in stakeholders' submissions (see section 4.1 of the **Supplementary Materials**). The analyses that fed into the co-design process and the discussions held across the workshops were key to building consensus among the working group on the bulk energy and shaping contracts that appropriately manage risk for all market participants in the interests of consumers. It is important to note that the co-design pilot working group requested that further work needed to be done on the operationalisation of the contracts. Utilising fungible contracts to underpin investments would benefit all stakeholders. Project proponents would benefit from having systemic risks (e.g. demand and technology change) removed from their project economics. Importantly, customers and retailers would benefit from the services continuing to be available (via derivative contracts) to manage future spot price risk and more transparent prices (see Figure 55).

Figure 55 – Competition and price discovery benefits of fungibility to different parties

Benefits for the **administrator...**	• Allows the ESEM Administrator to find the **cheapest provider** of the service • Minimises the need for the administrator to 'forecast' the future • Enhances **transparency** of decision making which drives accountability and competition
Benefits for the **project developers...**	• Developers are provided with a contract that allows them to **recover all their efficient costs**, not just the minimum revenue to attract financing • The key 'systemic' risks facing new projects are alleviated but the 'project specific' risks are retained by the project • Developers can **buy back** the contracts to 'pivot' their revenue strategy and use different engagement modes
Benefits for **consumers...**	• Better risk management leads to **lower and more stable costs** • More transparent prices across the system means consumers can identify a **'fair deal'**
For all **market participants...**	• Using contracts for 'services' creates **long-term price transparency** demonstrating the value of bulk energy, shaping and firming to all market participants • Contracts are available to participants in the future to manage risk in the spot market

5.11 The ESEM Administrator would recycle contracts back into the market

To ensure ongoing liquidity in electricity derivatives markets and to manage the risks of the ESEM Administrator holding derivative contracts, the ESEM Administrator would be required to recycle contracts that it has purchased back into the market. Contract recycling would build forward market liquidity, which stakeholders have highlighted as critical for retailers and C&I users to adequately manage risk.[381] This is especially important for small retailers, which the ACCC has highlighted as crucial in maintaining competitive pressure on retail prices.[382]

Over time, the continued exit of thermal generators – historically active participants in derivative markets – has the potential (in the absence of innovation) to reduce derivative market liquidity. PPAs, which have historically supported renewables investments, do not naturally provide the liquid and tradeable contracts needed by retailers to hedge their load efficiently.[383] Additionally, recent projects entering the NEM have received government assistance, partly removing project risk and reducing the incentive to participate in derivative markets.[384]

For these reasons, contract recycling would be an important part of the ESEM. The Panel envisages the ESEM Administrator would use a hybrid approach of selling down contracts in a structured way (documented in the ESEM Administrator's risk management policy), while also allowing proponents to buy offsetting over-the-counter (OTC) contracts prior to maturity. Additionally, the set of contracts ultimately adopted would influence how market participants engage with the ESEM.

Figure 56 – Illustration of ESEM contract recycling – net contract position at end of 2034

[381] Submissions to the initial NEM Review consultation from AFMA (p 4), AGL (p 10) and EnergyAustralia (p 7).
[382] ACCC (2023), Inquiry into the National Electricity Market: December 2023 Report, p 8.
[383] J Flottmann et al (2025), 'The Forward Market Dilemma in Energy-Only Electricity Markets', University of Cambridge Energy Policy Research Group.
[384] Ibid.

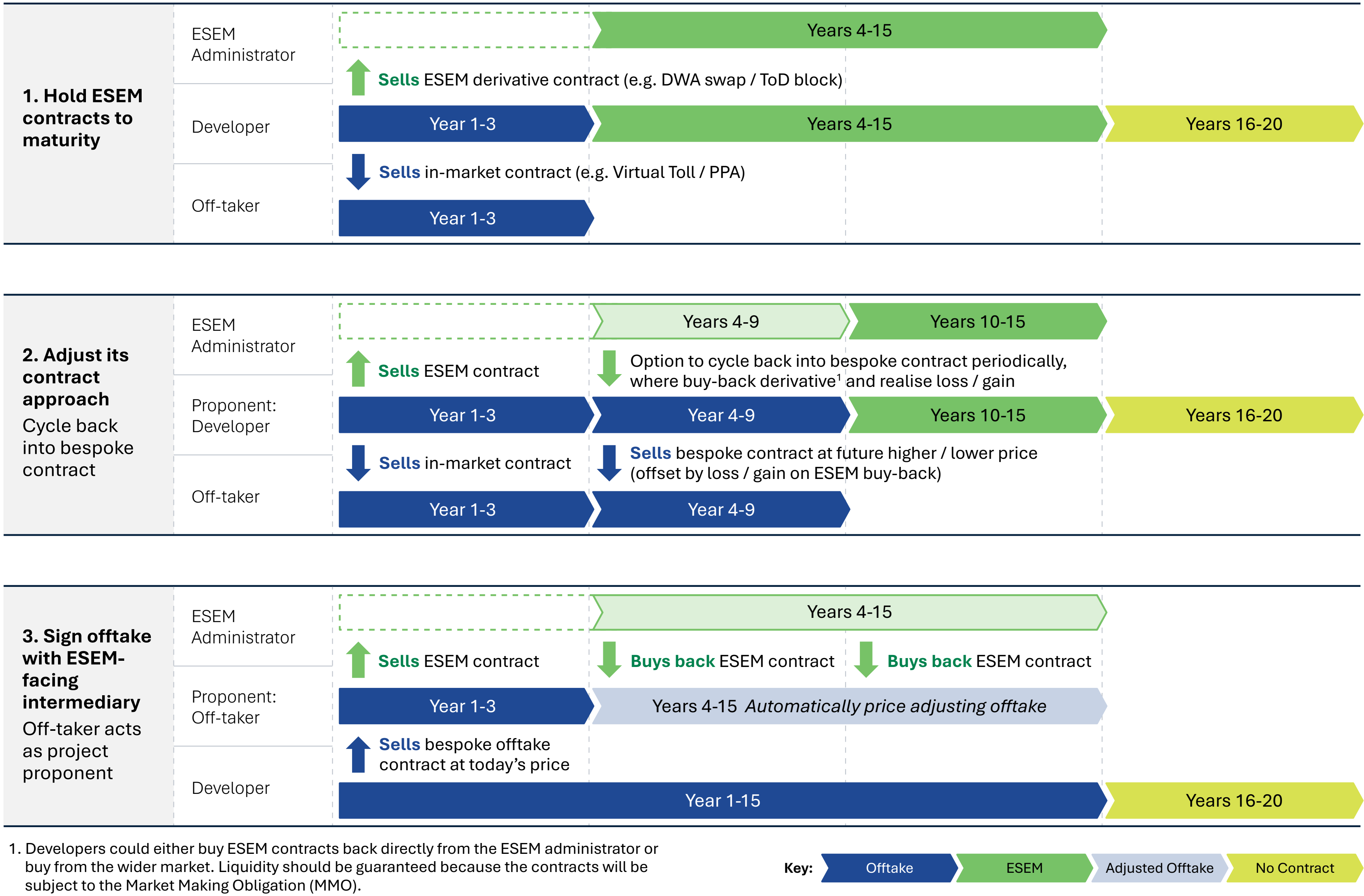
ESEM engagement modes

Using fungible contracts would open up a range of 'engagement modes' for entities looking to sell contracts from new electricity services projects into the ESEM (Figure 57). In addition to holding ESEM contracts to maturity, a project could choose to:

Adjust its contracting approach – a project could choose to buy back its contract from the ESEM Administrator at the prevailing market price and sell a different contract (such as a traditional PPA for bulk energy, or a revenue swap for shaping) to an off-taker. A project could adopt this approach for its operating life, or only for particular periods in response to conditions (such as during periods of scheduled maintenance).

Sign an offtake with an ESEM-facing intermediary – under this model, the off-taking intermediary rather than the new project would face the ESEM. An intermediary could bundle multiple new projects to sell into the ESEM, though careful work would be required to ensure the ESEM contracts still lead to the development of genuinely new projects.

Figure 57 – Standardised derivative contract strategies in the ESEM



1. Developers could either buy ESEM contracts back directly from the ESEM administrator or buy from the wider market. Liquidity should be guaranteed because the contracts will be subject to the Market Making Obligation (MMO).

5.12 The ESEM Administrator would be guided by a robust risk management framework

The ESEM Administrator would require a robust and transparent risk management framework to guide how risks are identified, assessed and managed in the delivery of its policy objectives – in particular, the risks associated with the use of derivative contracts. This risk management framework would ensure that design and implementation decisions are made in a disciplined manner consistent with the ESEM's overarching risk management objective.

> *… because the ESEM would hold significant financial positions in the market, it will be important to ensure that strong governance arrangements are in place, and that these are enshrined in legislation.* **– Productivity Commission**[385]
>
> *We note the ESEM administrator will hold considerable responsibility and market exposure once it commences its operations. Clearly defined obligations set by energy ministers which guide the administrator's market interactions are necessary to deliver against government targets, development of assets, derivative positions, risk management strategy and financial exposure, and auction processes… The ESEM administrator must possess the required skills, experiences, processes, systems, and hold an AFS licence.* **– EnergyAustralia**[386]
>
> *A single body with appropriate commercial and risk management skills should administer the ESEM, with clear statutory objectives guiding its operation, including promoting the construction of the right mix of assets and minimising costs to consumers.*
> **– Australian Energy Council (AEC)**[387]
>
> *The governance framework for the new government body that will run auctions, warehouse and sell contracts will be critical. We would advocate for prescription over discretion, so that the government's role is more machinery in nature rather than that of a public retailer.*
> **– RWE Renewables**[388]

Given electricity consumers would ultimately incur the costs and/or rebates of the ESEM's activities, the Panel proposes that risks be managed to facilitate the long-term financial interests of NEM consumers in relation to the risks arising from entering fungible and tradeable derivative contracts to enable new investment.

The governance approach underpinning the risk management framework should be established in the NEL and NER. The governance approach would:

- Specify the risk management framework and detail responsibilities for managing risk. This includes identifying the role of external oversight and jurisdictional governments in managing risk.
- Require the ESEM Administrator to produce a comprehensive Risk Management Policy for its board to approve, to be updated annually and provided to the Energy and Climate Ministerial Council (ECMC) for noting.

385 Productivity Commission (2025), Submission to the NEM Review Draft Report consultation, p 5.
386 EnergyAustralia (2025), Submission to the NEM Review Draft Report consultation, p 16.
387 AEC (2025), Submission to the NEM Review Draft Report consultation, p 2–3.
388 RWE Renewables (2025), Submission to the NEM Review Draft Report consultation, p 2.

- Require the ESEM Administrator be suitably qualified to perform such functions, including by having adequate and appropriately skilled resources and necessary accreditations (such as an Australian Financial Services Licence (AFSL)).

Stakeholder feedback on risk management and governance

Stakeholders expressed strong and consistent views that effective risk management and governance arrangements would be fundamental to the success of the ESEM. Stakeholders emphasised that the ESEM Administrator must be adequately resourced, suitably qualified and hold the necessary regulatory credentials, including an AFSL, to effectively manage commercial and operational risks. Stakeholders also stressed that the ESEM Administrator's risk management framework should be clearly defined, transparent and robust to manage the complex risks inherent in the mechanism.[389]

The Panel has recommended a strong governance and a transparent risk management framework, which will be critical to the credibility and long-term success of the ESEM. The ESEM Administrator should operate within a disciplined framework that clearly articulates its risk management objectives and should have the necessary expertise and authorisations to carry out its functions effectively and in the interests of consumers.

5.13 Governance arrangements for the ESEM would draw on existing policy and regulatory architecture

The ESEM's governance arrangements should provide for transparency and operational independence from individual governments, delivering consumer benefits and specific jurisdictional policy objectives through a stable, nationally consistent architecture.

Establishing the ESEM will require a coordinated package of legislative and regulatory changes, including amendments to the NEL and NER. The Panel has considered these implementation pathways and developed an Implementation Roadmap (section 1 of the **Supplementary Materials**), informed by stakeholder feedback on the Draft Report and engagement with the Australian, state and territory governments and relevant institutions.

The following principles have guided the Panel's recommendations on ESEM governance:

- **National consistency, jurisdictional sovereignty** – each NEM jurisdiction is constitutionally responsible for its electricity system, and this sovereignty should be respected as the ESEM is implemented. Jurisdictions should retain control of the pace and nature of their electricity system transition. This is not at odds with the ESEM contributing a greater level of consistency, predictability, transparency and stability to the NEM, as many existing jurisdiction-specific interventions can be integrated into the systemwide framework the ESEM will provide.
- **Stable, transparent architecture** – the mechanism should maximise transparency (e.g. informing the market on ESEM contract prices through the publication of forward pricing curves), administrative roles should be independent from government (e.g. awarding contracts in

[389] For example, submissions to the NEM Review Draft Report consultation from EnergyAustralia (p 16), Paul Verschuer (p 4) and CEIG (p 12).

procurement rounds), and clear rules should govern operations (e.g. framework for recycling of contracts).

- **Evolution, not revolution** – wherever possible, ESEM implementation should build on existing institutions and policy architecture. This would accelerate implementation timeframes, utilise existing skills and expertise, and limit market disruptions.

5.14 Non-financial considerations are best addressed through pre-qualification criteria and complementary policy frameworks

The Panel has maintained the position outlined in the Draft Report that the ESEM assessment process should remain simple, streamlined and transparent, with final selection determined on the basis of price. A standardised assessment approach focused only on financial criteria would minimise administration costs (which are ultimately passed through to consumers) and send clear and transparent signals to the market to encourage the required investment.

The Panel acknowledges the importance of achieving broader social and economic goals in ensuring the transition is successful. Accordingly, the Panel recommends that governments work collaboratively to establish complementary policy frameworks that deliver on these goals. The Panel notes that a community-led strategic planning process (e.g. at renewable energy zone level) would play an important role strengthening coordination, reducing the individual burden on developers, and enabling a streamlined framework for project development that drives positive social outcomes.

In this context, the Panel recommends that jurisdictions wishing to advance additional objectives (other than meeting the NEO or electricity-sector emissions reduction targets) through the ESEM be able to do so through the use of 'gateway' or pre-qualification criteria. This would ensure that only those projects and proponents who meet jurisdictional expectations regarding social licence contributions or other non-financial criteria may progress to price-based assessment.

5.15 Jurisdictions should work collaboratively with stakeholders to establish NEM-wide eligibility criteria where possible

Where jurisdictions elect to implement pre-qualification criteria, alignment of criteria between jurisdictions would support streamlined ESEM administration and would minimise administrative costs across participating jurisdictions. As such, the Panel recommends that governments work collaboratively to establish NEM-wide criteria where possible. The Panel has benefited significantly from engagement with various stakeholders on this important issue and notes a willingness to contribute to this process from these same stakeholders.[390]

Existing policy frameworks and capabilities should also be leveraged to reduce ESEM administration costs. This could involve governments establishing these key criteria with appropriate oversight bodies to provide advice to the ESEM Administrator about whether projects have achieved them. Where ongoing compliance with such criteria is required by the implementing jurisdiction, compliance should be enforced by the relevant authority through incorporating the commitments into the project development agreement or an adjacent contractual framework.

[390] Community Power Agency; Renewable Energy Alliance; Australian Council of Trade Unions; Electrical Trades Union; First Nations Clean Energy Network; Centre for Policy Development and WWF Australia.

Feedback on non-financial considerations in the ESEM

Stakeholder feedback to the Draft Report, and subsequent engagement with the Panel, revealed a wide range of views on whether and how the ESEM should incorporate non-price criteria within its assessments. Feedback centred primarily on project deliverability and social licence.

On **project deliverability**, some stakeholders argued that deliverability risks should be assessed to prevent contracts being awarded to non-viable projects, which could distort market outcomes and suppress genuine investment.[391] The Panel recognises this concern and has considered the trade-off between maintaining a simple, transparent assessment process and introducing more detailed deliverability checks. It supports an approach that retains streamlined price-based assessment while requiring adequately sized notice to proceed (NTP) bonds. NTP bonds would be callable where projects fail to reach NTP by a pre-agreed date and would deter non-delivery and maintain scheme integrity.

Project deliverability would be supported through the use of contracts under the ESEM that provide a full source of revenue for the electricity services they deliver (allowing for the recovery of all efficient costs). An important implication of this design is that proponents would need to carefully consider their revenue strategies and submit bids that reflect their long run marginal costs (including a reasonable return on capital). Several developers raised the importance of awarding viable projects for the ESEM's success,[392] with Squadron Energy raising the importance of the ESEM providing an all-in revenue strategy for deliverability.[393]

On **social licence**, some stakeholders expressed concern with the Panel's position that such criteria should operate as preconditions for participation rather than as competitive factors in the ESEM assessment. The First Nations Clean Energy Network (FNCEN) saw this as a step backwards from the CIS,[394] and the Renewable Energy Alliance (RE-Alliance) emphasised the benefits of having a nationally consistent approach.[395] The Panel engaged with a range of stakeholders on this issue, including through a series of engagements with Community Power Agency, RE-Alliance, the Australian Council of Trade Unions, the Electrical Trades Union, FNCEN, Centre for Policy Development and WWF Australia.

The Panel recognises that delivering a successful transition requires consideration of broader social and economic objectives. To that end, the Panel recommends that governments work together to develop complementary policy frameworks that embed these goals. Harmonising gateway criteria could be a means of reducing compliance costs and provide for a more efficient and effective outcome. A community-led strategic planning process would significantly improve coordination, reduce the burden placed on individual developers and create a more efficient and consistent pathway for project development that supports positive social outcomes. The Panel recommends that jurisdictions apply any gateway criteria to address non-financial policy objectives and, where ongoing compliance is required, this be enforced by the relevant authority by incorporating the commitments into the project development agreement or an adjacent contractual framework.

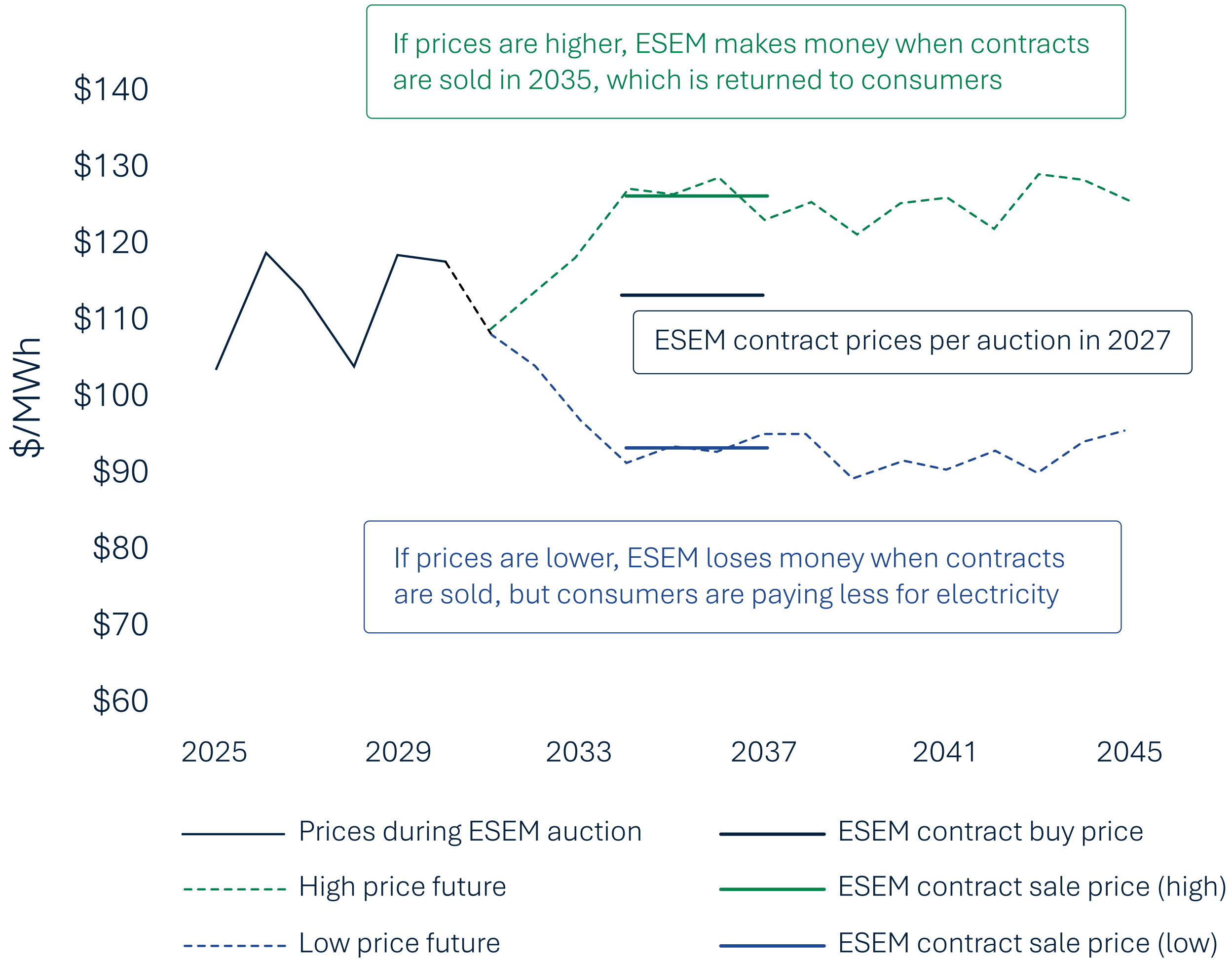
391 RWE Renewables (2025), Submission to the NEM Review Draft Report consultation, p 3.
392 Submissions to the NEM Review Draft Report consultation from Tilt Renewables (p 12), Akaysha (p 14) and RWE Renewables (p 3).
393 Squadron Energy (2025), Submission to the NEM Review Draft Report, p 7.
394 FNCEN (2025), Submission to the NEM Review Draft Report consultation, p 2.
395 RE-Alliance (2025), Submission to the NEM Review Draft Report consultation, p 3.

Other stakeholders supported the approach proposed by the Panel in the Draft Report, agreeing that jurisdictional non-financial requirements should be treated as prequalification conditions rather than as part of the ESEM's competitive merit assessment. Origin Energy recognised that multiple bid parameters would increase complexity and undermine the transparency of procurement outcomes and associated market benefits.[396]

5.16 Residual costs or rebates should flow to consumers

Under the ESEM, the ESEM Administrator will bear some of the risks of investment in new bulk energy, shaping and firming projects. Depending on the prices the ESEM Administrator pays for contracts in procurement rounds and the price it receives when it recycles the contracts back into the market, this risk could be realised as a financial loss or gain, as shown in the hypothetical example below.

Figure 58 – Hypothetical example of cost recovery[397]



The Panel proposes that residual costs or rebates arising from the difference between buy and sell prices should be recovered from or returned to consumers served by the regional reference node

[396] Origin Energy (2025), Submission to the NEM Review Draft Report consultation, p 14.
[397] This is a simplified, illustrative example; actual costs or rebates will be complex to determine and depend on a large range of factors.

against which contracts are settled. This methodology balances principles of simplicity, transparency and beneficiary-pays. The cost recovery mechanism should be established in the NEL and NER and operationalised by the ESEM Administrator in accordance with these principles.

The Panel has considered several approaches to a cost recovery mechanism building on the principles proposed in the Draft Report (see details in section 6.1 of the **Supplementary Materials**). The Panel's recommended cost recovery mechanism:

1. **Supports residual costs or rebates from the ESEM to remain inside the NEM by being incorporated into the NEM (AEMO) settlement process.** Costs or rebates would therefore ultimately be recovered from or paid to consumers.
2. **Results in any costs or rebates from the ESEM being settled in the region against which an ESEM derivative contract is settled.** Derivatives under the ESEM would be written against the node for the NEM region where the service is to be delivered. In addition to this default approach, there should be provision for jurisdictions to share the costs of mutually beneficial investments in other ways if appropriate, akin to the recent interconnector cost sharing rule change.[398] Market participants that expect a proportion of their services to be exported when the price is higher in a different region can benefit by purchasing settlement residue distribution units.
3. **Balances the benefits of administrative efficiency and simplicity against matching the form of rebates or costs to the underlying service.** For example, residual costs or rebates from bulk energy and shaping services should be linked to grid-based electricity consumption ($/MWh rebate or charge), while residual costs or rebates from firming services should be based on a combination of fixed (e.g. $/NMI/year) and variable charges. This is because firming services are required for all consumers during times of high demand and low bulk energy generation.
4. **Recovers or returns costs or rebates in the relevant year.** For example, if contracts for the year 2035 are closed out at a loss, the costs would be recovered from consumers in 2035.
5. **Supports stability in retail prices.** This will require costs or rebates to be known in advance so retailers can reflect their allocation onto bills.
6. **Includes provisions for cost relief for market customers who contract for new investment outside the ESEM.** The Panel considers there should be a mechanism to allow market customers who contract for new investment outside of the ESEM to receive relief from recovery of residual costs or return of rebates associated with the ESEM.

[398] AEMC (2024), Providing flexibility in the allocation of interconnector costs.

Stakeholder feedback on cost recovery

Some stakeholders supported allocating costs and rebates through the Panel's proposed user-pays recovery mechanism,[399] or a similar causer-pays[400] or beneficiary-pays approach.[401] Other stakeholders questioned the Panel's position that costs should be recovered from consumers:

"*Emission reductions are a broad societal goal that goes well beyond the electricity sector and energy consumers. When emissions policies impact on the electricity sector – such as accelerating the need to replace emissions-intensive capacity and build new transmission – we think there is a very good argument that taxpayers are the right constituency to pay, since all citizens benefit.*" **– Energy Consumers Australia**[402]

Some stakeholders suggested that cost recovery should be done via network tariffs[403] while other stakeholders strongly viewed that cost recovery via network charges should be avoided.[404]

The Panel has maintained its view that the costs or rebates of the ESEM should primarily flow through to consumers in proportion to the benefits for each user, given the mechanism would deliver benefits relating to all limbs of the NEO: reliability, price and emissions. This is more of an enduring approach than mechanisms that depend on government funding, which can vary as government priorities change – noting that many stakeholders explicitly supported the enduring nature of the proposed ESEM.[405] However, the Panel is proposing that the ESEM be established with sufficient flexibility for governments to contribute taxpayer funds, should they choose to do so.

399 See submissions to the NEM Review Draft Report consultation from Energy Networks Australia (ENA) (p 6–7) and ACEN Australia (p 10).
400 AEMC (2025), Submission to the NEM Review Draft Report consultation, p 27.
401 Rainbow Power Company (2025), Submission to the NEM Review Draft Report consultation.
402 Finncorn consulting (for Energy Consumers Australia) (2025), Submission to the NEM Review Draft Report, p 7.
403 See submissions to the NEM Review Draft Report consultation from Origin Energy and ACEN Australia.
404 For example, ENA (2025), Submission to the NEM Review Draft Report consultation, p 4.
405 For example, see Submissions to the NEM Review Draft Report consultation from: Squadron (p 7), Flow Power (p 11), Transgrid (p 1), AEMC (p 3), EnergyAustralia (p 2), SEC (p 11), APGA (p 3), AEMO (p 2) and Productivity Commission (p 4) and CEC (p 2).

Recommendation 10B: Where cost-effective, projects facilitated through the ESEM should also be able to provide ESS

The ESEM Administrator should be able to enter contracts with market participants to provide ESS where this is demonstrated to be cost-effective. The ESEM Administrator should coordinate with transmission network service providers (TNSPs) and establish a secondary contract for those ESS-related elements.

5.17 Work is underway but more is needed to deliver timely and sufficient investment in ESS

As outlined in **Chapter 1: Introduction to the NEM**, Australia's decarbonisation efforts have primarily focused on replacing coal-fired generation with low-cost, inverter-based renewable energy. This transition has led to a decline in ESS traditionally supplied by synchronous coal-fired generators.

Recent under-investment in ESS reflects several factors: weak or absent price signals, fragmented and overlapping procurement processes, and the non-excludable nature of these services. Forecasting challenges and the lag between identifying a need and delivering a solution further contribute to the shortfall. These issues are further exacerbated by location-specific requirements and protracted regulatory processes, which slow delivery and increase the need for out-of-market interventions to maintain system security.

In short, risks around ESS are asymmetric: the consequences of delivering ESS too late are far greater than the costs of providing them slightly early. As the pace of decarbonisation increases, the system will require substantial new investment in generation, storage and transmission infrastructure. Integrating ESS into project design from the outset presents a cost-effective opportunity to enhance overall system efficiency, reduce total costs, and avoid costly retrofits in the future.

Several reforms already underway (see Figure 59) are designed to address current issues:

- **AEMC's Improving Security Frameworks Rule** enables AEMO to procure transitional services and enhances the inertia framework used by TNSPs to trigger procurement.
- **The Reliability Panel's review of the System Restart Standard** reassesses whether existing restart obligations and incentives remain appropriate as the energy system evolves.
- **AEMO's Application of Advanced Grid-Scale Inverters in the NEM White Paper** quantifies inverter capabilities and refines procurement approaches for services such as inertia and voltage control.
- **AEMC's access standards rule changes** strengthen technical requirements for new connections to ensure projects are capable of contributing ESS where feasible.

The ESEM would present an opportunity to deliver ESS more efficiently and on a timelier basis by better coordinating investment decisions. Improved coordination would reduce the risk of timing errors, short-term under-investment and long-term over-investment, and help to capture co-benefits during project development, thereby avoiding the need for costly retrofits or stand-alone infrastructure in the future.

Stakeholder feedback on procurement of ESS through the ESEM

While the Panel's view is that the procurement of ESS should occur through secondary contracting, several stakeholders suggested that the ESEM Administrator should be able to contract ESS as core ESEM services.

The AEC and CEC proposed a model late in the Panel's consultation process for how ESS could be elevated through the ESEM. As the feedback was received at a late stage of the Review, there was insufficient time for detailed stakeholder consultation on this proposal. The Panel considers that this model warrants further consideration in parallel to implementation of the Panel's recommended ESEM framework.

"*This paper advocates extending the ESEM framework to include ESS procurement in a coordinated manner with AEMO and Transmission Network Service Providers (TNSPs) by elevating ESS contracts to the same level as those for bulk energy, shaping and firming services, while accommodating the unique characteristics of ESS.*

Extending the ESEM framework to ESS would involve:

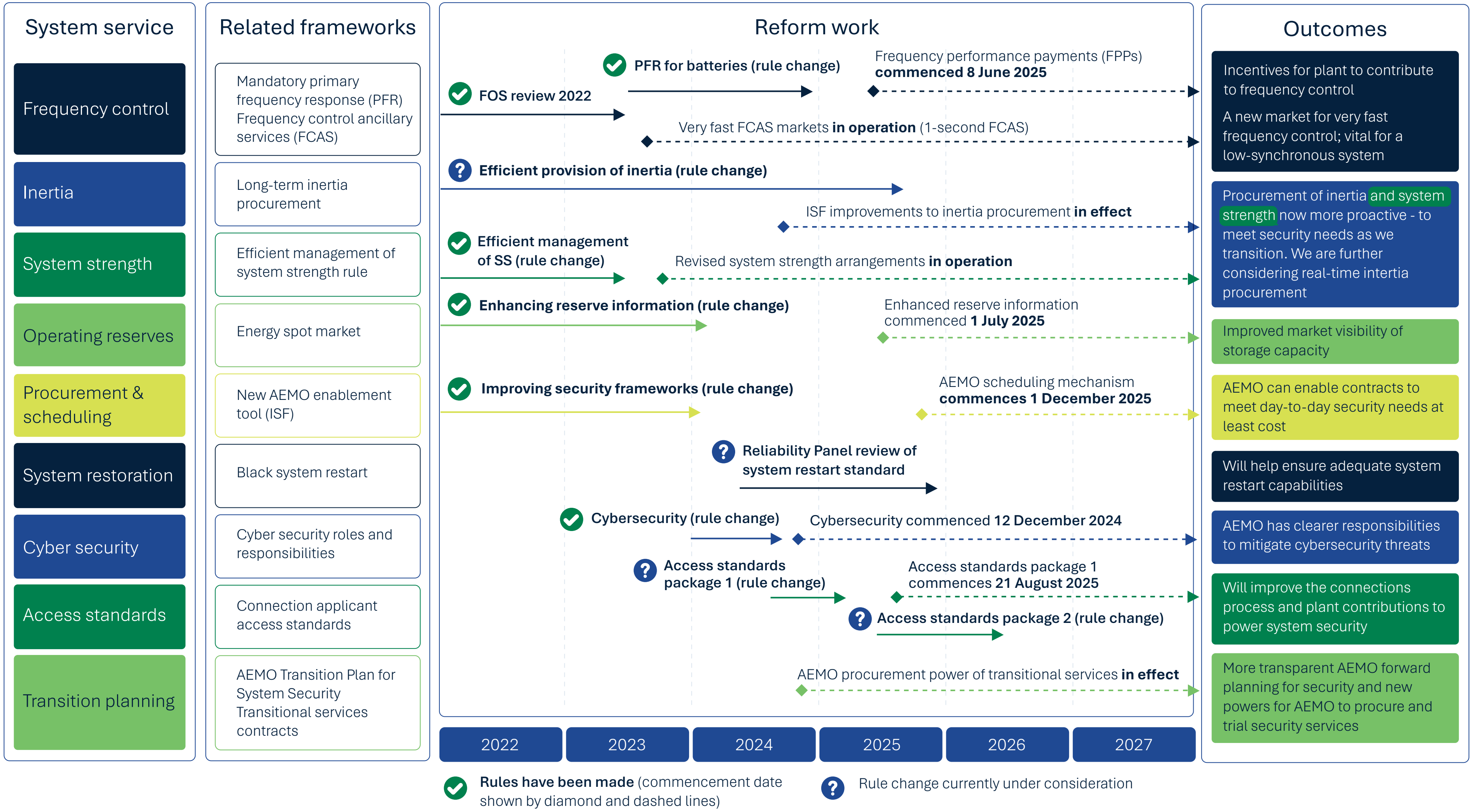
- *Developing specifications and standards for relevant ESS.*
- *Creating long-term standardised contracts for categories of ESS.*
- *Setting clear procurement trajectories informed by integrated modelling of reliability and security needs.*
- *Ensuring eligibility for ESS contracts is technology agnostic.*
- *Setting clear procurement trajectories informed by integrated modelling of reliability and security needs.*
- *Establishing a competitive bidding process to promote transparency and cost-effectiveness.*

The core of this requirement is that the ESEM Administrator should work with AEMO and the TNSPs to determine an ESS procurement trajectory and to co-optimise procurement of energy resources with the procurement of ESS. The key recommendations are:

A. *The ESEM Administrator should be the responsible party for ESS procurement.*
B. *The ESEM Administrator should determine the service shortfalls and long-term system security risks.*
C. *The ESEM Administrator should standardise the procurement of ESS.*
D. *The ESEM Administrator should consider establishing ESS contracts in line with the needs of the power system.*" **– AEC & CEC**[406]

[406] AEC & CEC (2025), Essential system services contract procurement through ESEM: Submission to the NEM wholesale market settings review.

Figure 59 – The AEMC's system security work program, rule commencement and implementation timelines



5.18 Timing constraints, narrowly defined regulatory requirements and muted investment signals pose challenges to the provision of ESS

TNSPs and AEMO each have a defined responsibility for providing ESS in the NEM. TNSPs procure network support and control ancillary services (NSCAS), system strength and inertia services. Over the past five years, system strength and inertia have consistently been among the most frequently declared services in shortfall in the NEM, prompting multiple remediation programmes (Figure 60).

As monopoly providers, TNSPs' revenues are regulated by the AER. If they undertake work that has not been planned or approved in advance, they may not be permitted to recover those costs from consumers. This creates a disincentive for pre-emptive or strategic co-investment, even when early action would help manage the asymmetric risks associated with being too late in delivering ESS.

> *The transmission revenue recovery process is not suited to the recovery of unpredictable and volatile costs, and these cash flow impacts can have flow on effects on financing costs and expenditure programs.* **– Energy Networks Australia (ENA)**[407]

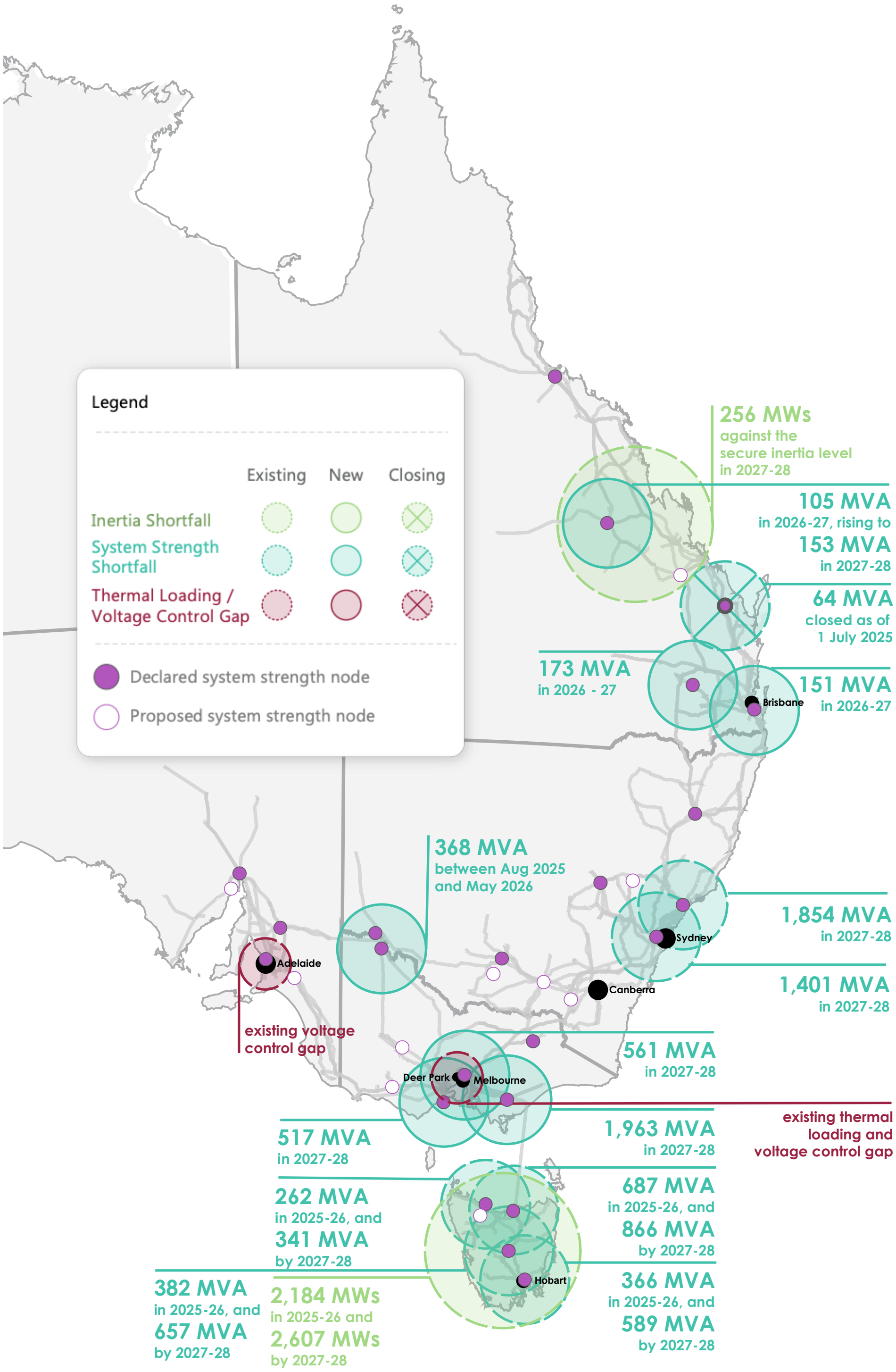
The Regulatory Investment Test for Transmission (RIT-T) is a prescribed economic assessment process that TNSPs must follow to evaluate proposed projects. It includes multiple consultation stages and may take more than 12 months, depending on complexity. Due to both its duration and the differing regulatory settings that apply to networks and generators, the RIT-T often does not align with the investment timelines of new projects that may be capable of also delivering ESS.

The RIT-T is structured around a narrowly defined 'identified need', which limits flexibility for opportunity-driven investments (such as integrating ESS capability into new projects) unless the ISP has already indicated a requirement for that enhancement.

Together, these timing constraints, narrowly defined regulatory requirements and muted investment signals create a mismatch between when the system needs new services and when the existing frameworks can respond.

[407] ENA (2025), The NEM wholesale market review.

Figure 60 – System security needs across the NEM



Source: AEMO 2024, System strength, inertia and NSCAS reports infographic.

As noted above, market bodies are already progressing reforms to ESS provision (see Figure 59). Additional coordination through the ESEM would complement these efforts by reducing duplication of investment and improving the efficiency of investment decisions. By addressing this gap, the ESEM would enable timely and co-optimised deployment of assets that might otherwise be delayed or overlooked. This approach would help reduce total system costs and ensure the future system has the services it requires.

Case study: Cost effective solutions – enhancing system strength with Townsville Power Station

In December 2021 AEMO declared an immediate system strength shortfall of 44 to 65 megavolt-amperes (MVA) at the Gin Gin system strength node in Central Queensland. This shortfall was due to the projected decline of synchronous machines online in the region. In May 2022 AEMO updated the shortfall to up to 64MVA for the period to 1 December 2025.

System strength is crucial for the stability of the power system, especially with the increasing penetration of inverter-based generation. The shortfall at Gin Gin was declared because the system strength services were projected to fall below the minimum requirements for more than 1% of the time under typical dispatch patterns. Powerlink needed to address this shortfall to ensure the stability and reliability of the power system in Queensland.

Approach

Powerlink commenced an expression of interest process for short- and long-term non-network solutions to address the fault level shortfall at the Gin Gin node. After detailed analysis, Powerlink concluded that adding a clutch to the shaft between the gas turbine and the synchronous generator at the Townsville Power Station was the least-cost option to address the shortfall. This conversion allows Townsville Power Station to operate as a synchronous condenser providing system strength without moving the gas turbine or generator.

The project involves converting the gas turbine and generator to a hybrid rotating grid stabiliser. This conversion includes retrofitting an SSS Clutch, which allows the unit to operate as a synchronous condenser. Once delivered, the Townsville Power Station, operating as either a generator or as a synchronous condenser, will provide sufficient system strength for inverter-based generation facilities in North and Central Queensland to operate stably.

Benefits from the installation of a clutch at Townsville Power Station include:

- **Cost effective solution:** the conversion to a hybrid rotating grid stabiliser is up to 50 per cent less costly than installing a new synchronous condenser.
- **Timely implementation:** the project can be completed in 18 months, compared to over 36 months for a new synchronous condenser.
- **Revenue generation:** the plant owner, Ratch Australia, will gain a new revenue stream from providing grid services.
- **Flexibility:** Townsville Power Station will have the capability to switch flexibly between power generation and grid stabilisation modes.
- **Grid stability:** the electrical inertia provided by Townsville Power Station in grid stabilisation mode is calculated to be around 250 MWs and around 1,000 MWs in power generation mode.

The conversion of the Townsville Power Station to a hybrid rotating grid stabiliser represents a significant step in enhancing system strength and grid stability in Queensland.

By providing a cost-effective and timely solution to the system strength shortfall, Townsville Power Station plays a crucial role in supporting the transition to renewable energy sources and ensuring the stability of the power system.

By integrating ESS considerations earlier in the investment process rather than relying on costly retrofits later, the ESEM should facilitate lower-cost ESS provision and ultimately reduce costs for consumers.

5.19 The ESEM should be used to complement other solutions to coordinate procurement of ESS

The Panel recommends allowing proponents of bulk energy, shaping and firming services to enter into secondary contracts for ESS where this is technically feasible and cost-effective. Coordinated planning and procurement would support the efficient integration of ESS as a co-benefit of new projects. The ESEM would help to coordinate investment over the longer term but should not be seen as a solution for immediate shortfalls or as replacing the obligations on AEMO and TNSPs to manage the provision of ESS, unless governments were to implement the framework suggested by the AEC/CEC proposal.[408]

Incorporating ESS capabilities during the design stage of new projects is generally more cost-effective than retrofitting or building stand-alone ESS infrastructure. While dedicated assets (such as synchronous condensers) could still be required in some areas, co-optimisation of ESS capabilities with other services where practicable would reduce overall service delivery costs. For example, grid-forming capabilities in batteries or clutches on gas turbines could provide lower-cost alternatives to stand-alone ESS solutions.

A coordinated procurement process under the ESEM would identify and capture these capabilities from the outset. Aligning procurement signals would overcome fragmented incentives, reduce the risk of inefficient timing and support the concurrent delivery of generation and system services. It would also allow for more strategic siting of ESS assets to maximise network value and help avoid duplicative infrastructure, as seen in the Townsville Power Station case.

> *Any recommended mechanism, including standalone government schemes, needs to encourage bundling of technologies with system service capabilities so it contributes to the cost efficient and timely delivery of the capabilities needed to manage a high [inverter-based resource] system and better manage orderly exit of coal from the system.* **– AEMO**[409]

TNSPs would remain responsible for delivering system strength and inertia under the existing regulatory framework. Coordination through the ESEM would support, rather than diminish, their role by helping align long-term investment decisions and reduce duplication.

[408] AEC & CEC (2025), Essential system services contract procurement through ESEM: Submission to the NEM wholesale market settings review.
[409] AEMO (2025), Submission to the Initial NEM Review consultation, p 1.

5.20 Using the ESEM to coordinate ESS would require clearly defined ESS requirements and a transparent procurement process

The recommended approach rests on two core principles:

1. **Clarity:** clearly defining ESS requirements.
2. **Transparency:** reporting the pricing outcomes of any ESS procurement.

Coordination between AEMO and the ESEM Administrator would be essential to implementing this approach. AEMO's annual forecasts covering system strength, inertia and NSCAS needs would continue to define ESS requirements at key locations.[410] To ensure operational readiness, proponents would also need to demonstrate compliance with the technical standards required for AEMO's enablement tool.[411] AEMO would continue to deepen its work on ESS, including by defining and forecasting services and system needs. This increasingly detailed focus would provide the clarity and transparency needed to support the Panel's recommendation, which some stakeholders identified as vital.

> *The Panel's recommendation for the ESEM to facilitate the provision of system services could help to overcome some of the issues identified with existing frameworks (timing constraints, narrowly defined regulatory requirements and muted investment signals). However, prior to implementing the proposed solution (i.e. enabling project providers to submit an ESS bid as part of ESEM tenders and receive a secondary ESS contract), a first step should be for AEMO to more specifically define the ESS required in the market, and then consider how network and non-network solutions can be best traded-off to facilitate the most efficient / least cost service provision for the market.* **– Origin**[412]

To be clear, there would be no requirement on project providers to incorporate ESS into their projects for bulk energy, shaping and firming services. However, when conducting procurement rounds, the ESEM could consider both of the following:

1. A core bid for bulk energy, shaping, or firming services only.
2. An optional 'ESS bid' that outlines the incremental cost of providing additional ESS capability beyond any connection obligations that may apply.

The core bid would be assessed through the standard competitive procurement process. If a proponent's primary bid is successful, the ESEM Administrator would then consider the proponent's accompanying ESS bid. Where the ESS proposal is reasonable and aligned with identified system needs, the ESEM Administrator could enter into a secondary ESS contract. This secondary contract would provide a stable revenue stream to cover incremental equipment costs, such as clutches for gas turbines or grid-forming functionality in batteries. To promote transparency, the ESEM Administrator would publish the successful bids' marginal costs of delivering ESS.

[410] It could be beneficial to bring these forecast horizons into alignment to enhance coordination and planning. These forecasts provide proponents with clear guidance on baseline ESS requirements.
[411] AEMO (2025), Improving Security Frameworks – High Level Implementation Assessment, p 17.
[412] Origin (2025), Submission to the Initial NEM Review consultation, p 18.

Given the locational nature of ESS and the smaller pool of eligible providers, competitive pressure on ESS bids may be limited. This is particularly the case where a shortfall is large or urgent. To manage this, the ESEM Administrator would compare ESS bid costs with those paid by TNSPs for similar services, such as the annually published AER-approved unit prices for system strength in each TNSP region.

Where an ESS contract aligns with a need that passes the RIT-T, the contract would be novated to the relevant TNSP, enabling integration into existing regulatory frameworks. Alternatively, if the ESEM does not directly contract for ESS, it should share relevant information with TNSPs to support price discovery and streamline the regulatory approval process.

Stakeholder feedback on procurement of ESS through the ESEM

Stakeholder feedback generally supported changes to the current framework to improve transparency and coordination, and to elevate how ESS are planned for and procured. Several stakeholders supported the recommendation in the Draft Report as an improvement, or at least a step in the right direction.[413]

Several other stakeholders did not favour a secondary contracting approach, preferring instead to elevate ESS by developing markets or assessing ESS as part of primary bids alongside bulk energy, shaping and firming services.[414] Several stakeholders suggested establishing a dedicated ESS workstream and working group to investigate the barriers to ESS more broadly rather than only within an ESEM-context.[415] Moreover, the AEC and CEC proposed a model late in the Panel's consultation process (discussed earlier under **Model proposed by the AEC and CEC**) for how ESS could be elevated through the ESEM. While the Panel sees merit in the AEC/CEC proposal, it has had insufficient time to consult on this proposal in detail.

The Panel's view is that the AEC/CEC proposed alternative contracting approach should be considered in the detailed design and implementation phase of the ESEM. If the workability of this alternative design is not established, the Panel considers its proposed design for the ESEM Administrator to procure ESS through secondary contracts would be a no-regrets approach.

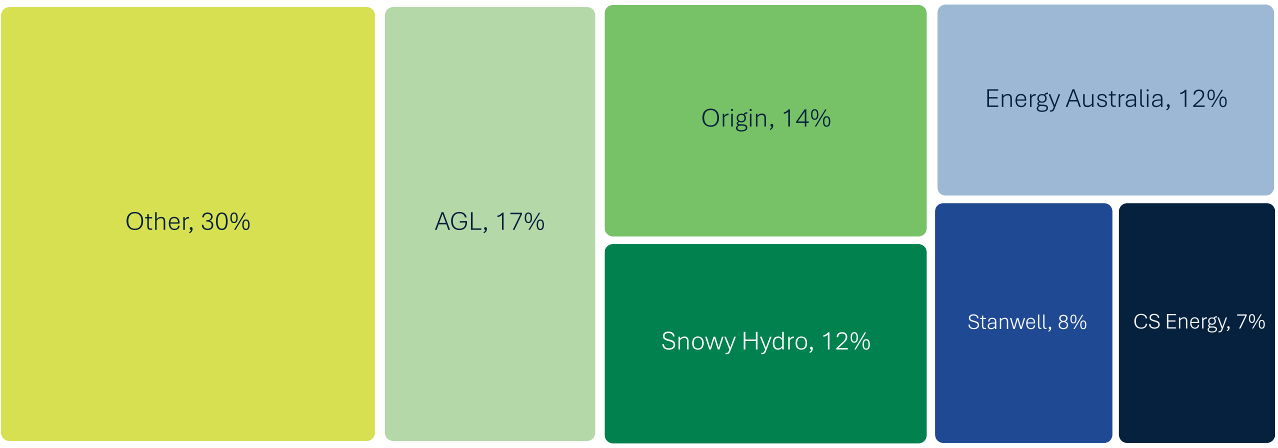
[413] See Submissions to the NEM Review Draft Report consultation from Alinta Energy, APA Group, AEMC, AEMO, APGA, CEIG, ENA, Enel X Australia, LDES Council, Origin, Rainbow Power Company and Transgrid.
[414] See Submissions to the NEM Review Draft Report consultation from AEC, ASTEA, CEC, CS Energy, David Lee, EnergyAustralia, ENGIE, Hydro Tasmania, RayGen, SEC, Snowy Hydro and Tesla.
[415] See Submissions to the NEM Review Draft Report consultation from Akaysha Energy, AEC, CEC, Eku Energy, Fluence and Tesla.

Recommendation 10C: The ESEM Administrator should apply market concentration thresholds, independently set by the AER, when setting eligibility criteria for participating in ESEM procurement rounds[416]

5.21 Competition in the NEM is vital for driving efficiency, innovation and affordability

Concentrated ownership of dispatchable assets limits competitive pressure. The AER has noted market concentration has reduced in recent years as the energy transition has brought new players into generation and retail markets.[417] However, ownership of dispatchable generation remains relatively concentrated and a small number of large participants are often needed to meet demand during periods of low renewable production.[418]

Figure 61 – Share of dispatchable capacity, 2024

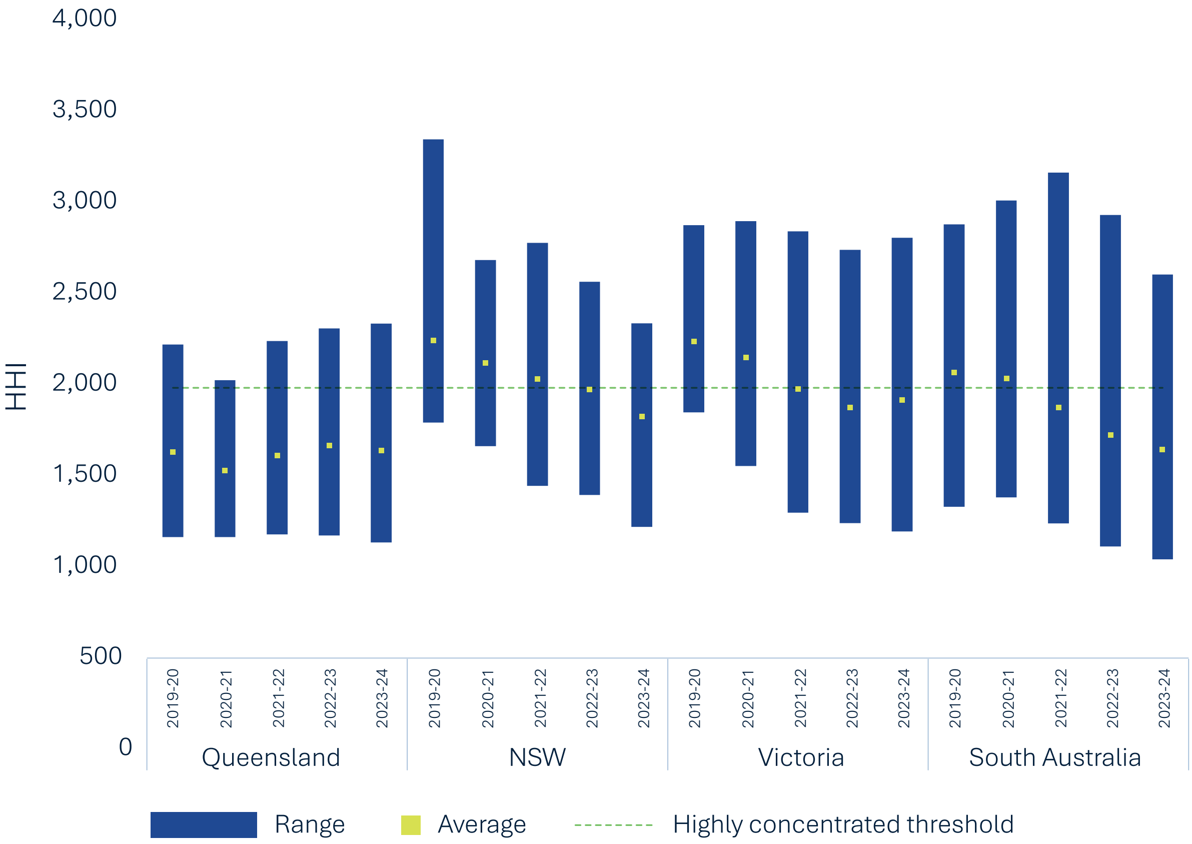


Source: AER. Data as of 31 December 2024. Dispatchable capacity includes gas, coal, batteries and hydro.

Figure 62 shows the Herfindahl Hirschman Index (HHI)[419] for NEM mainland regions for each bid interval from 2019–20 to 2023–24. The AER considers a score of 2,000 to indicate a market that is highly concentrated, though notes some jurisdictions consider 1,800 or above as highly concentrated.[420] While the median HHI score was under 2,000 in every region in 2023–24, during periods of low wind and solar output Victorian HHI scores reached as high as 2,800 and South Australian scores reached 2,600.[421]

416 This aspect of the ESEM is not intended to be utilised in Tasmania, which has a unique market structure due to the predominance of its state-owned hydro assets.
417 AER (2024), Wholesale electricity market performance report, p 2.
418 Ibid.
419 The Herfindahl-Hirschman index is a measure of the competitiveness of an industry in terms of the market concentration of its participants.
420 Op Cit., p 51.
421 Op Cit., p 56.

Figure 62 – Herfindahl Hirschman Index by jurisdiction, 2019–24



Source: Adapted from AER (2024), [Wholesale electricity market performance report](), Figure 4.5 and p 51.

5.22 As the energy transition continues to unfold, competition will remain central to good consumer outcomes in the NEM

The Panel recommends that the ESEM Administrator should apply competition thresholds, independently established by the AER, when determining which projects are eligible to participate in ESEM procurement rounds. This would ensure the scheme does not support projects that could materially harm competition. Assessing competition effects at the eligibility stage would also provide early certainty and avoid unnecessary administrative costs for proponents with high market shares who are unlikely to meet the threshold.

In considering competition effects, the ESEM Administrator would be bound by AER-determined market concentration thresholds for ESEM services. The AER's existing market monitoring and reporting functions would be expanded to include maintaining a register of market concentration thresholds for each ESEM service in each NEM region, excluding Tasmania.

The ESEM Administrator should clarify that any project expected to increase the proponent's market share to breach or further breach an AER-set market concentration threshold for a specific ESEM service in a region would not be eligible to participate. For example, this could mean the ESEM would not support a project proponent to provide firming services in Region A but could support the same proponent to provide firming services in other NEM regions (or to provide bulk energy and shaping services in any region). The project proponent could still proceed to develop and provide new firming services in Region A without ESEM support.

> *We support the suggestion in the paper for the ESEM administrator to limit contracting with participants with large market shares that would lead to a breach of a market concentration benchmark. This need not be administered on a whole of market basis, but rather in each of the three energy services. That is, if the participant wished to increase their investment in the energy system, they would either have to make an investment without ESEM coverage in the same energy service - where they had reached the concentration limit - or invest in a resource that provided one of the other two energy services.* **– Justice and Equity Centre**[422]

Stakeholder feedback on market concentration considerations

Stakeholder feedback generally supported the ESEM Administrator considering market concentration when awarding ESEM contracts to projects.[423] Key points raised included:

- **Publicly owned companies:** Union groups supported a market concentration provision but requested exempting publicly owned companies.[424] Conversely, Incite Energy supported directly and transparently limiting the role of government-owned entities.[425] The Panel's view is to maintain its recommendation from the Draft Report, which is consistent with competitive neutrality principles under which publicly owned companies operate. To be clear, the market concentration provision would not apply in Tasmania where market conditions are less able to support effective competition.
- **Flexibility:** Several submissions preferred a flexible approach over using market concentration thresholds.[426] Alinta suggested enabling proponents above the threshold to participate through a ring-fenced entity or special purpose vehicle.[427] The Panel considers its recommendation enables flexibility by giving the AER discretion with how it sets market concentration thresholds, which could vary with service types, NEM regions and time. The AER would also provide a methodology for calculating ownership shares – and could form a view on whether ring fencing and other approaches (e.g. sharing offtake volumes) would affect a participant's share. The Panel considers there would be certainty and administrative efficiency benefits in project proponents knowing the relevant thresholds in advance of submitting bids. A subjective assessment of market concentration would not align with the principles of simple, price-based assessment and would not provide sufficient clarity to investors.
- **ESS:** ENA and the Smart Energy Council (SEC) added that market concentration should also be considered when procuring ESS.[428] The Panel considers this concept should be further explored during the ESEM's detailed design stage, although there would be additional complexities with assessing market concentration in the provision of ESS. For instance, ESS such as inertia and system strength may inherently face greater competition barriers as they are more geographically specific services.

[422] Justice and Equity Centre (2025), Submission on the NEM Review Draft Report, p 8.
[423] For example, see Submissions to the NEM Review Draft Report consultation from Bluescope, CEIG, EMX, Flow Power, Fluence, IEEFA, Incite Energy, Justice and Equity Centre and SEC.
[424] ETU (2025), Submission on the NEM Review Draft Report consultation, p 3; ACTU (2025), Submission on the NEM Review Draft Report, p 1.
[425] Incite Energy (2025), Submission on the NEM Review Draft Report consultation.
[426] See for example, Submissions to the NEM Review Draft Report from AFMA (p 4) and CEIG (p 7).
[427] Alinta (2025), Submission on the NEM Review Draft Report consultation, p 5.
[428] ENA (2025), Submission on the NEM Review Draft Report consultation, p 5; SEC (2025), Submission on the NEM Review Draft Report consultation, p 11.

5.23 The ESEM would drive higher levels of competition over time

Electricity derivative market liquidity underpins a competitive retail sector, as it enables retailers to hedge according to their specific needs.[429] Limited trading volumes can lead to wider bid–ask spreads and higher risk premiums embedded in contract prices, while producing less reliable price signals for future investment decisions.

Independent retailers and smaller new entrant generators are unlikely to be viewed as investment-grade creditworthy counterparties by banks, limiting their ability to contract at low cost. Trading on exchanges such as the Australian Securities Exchange (ASX) requires substantial capital for margins, again disadvantaging smaller entities with limited balance sheets[430] (see discussion at **Recommendation 8**). Similarly, favourable OTC contract terms often require strong credit ratings, or bank or parent company guarantees.

The ESEM could contract with smaller parties, with the ESEM Administrator absorbing some credit risks as appropriate. A carefully-design risk management framework would support the ESEM Administrator to prudently manage such risks.

[429] ACCC (2018), Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry – Final Report, p 113.
[430] AER (2022), Wholesale Electricity Market Performance Report – December 2022, p 54.

Recommendation 10D: The ESEM Administrator should facilitate the procurement of strategic reserves covering high-impact, low-likelihood events, with quantities to be procured at the discretion of jurisdictions on advice from the Reliability Panel

In addition to in-market services, the Panel recommends that the ESEM Administrator be able to procure 'strategic reserves' services, which would be a long-term out-of-market reserves service to address specific challenges.

Service providers of strategic reserves would:

- receive a flat annuity contract for all relevant periods, with associated availability obligations
- remain out-of-market unless specific conditions (established in clear and binding rules) are met
- be procured on the direction of jurisdictional energy ministers, informed by advice from the Reliability Panel.

How would the strategic reserves differ from the reserves currently procured under the Reliability and RERT?

Strategic reserves would be long-term out-of-market reserves competitively procured under the ESEM at the direction of participating jurisdictions that value a higher reliability standard than the NEM-wide standard.

These reserves would be for very-low-likelihood but very-high-consequence events such as prolonged renewable energy shortfalls. Effectively addressing these events requires using a deterministic (rather than probabilistic) approach. They would only be triggered in ex-ante defined conditions as an alternative to load shedding, with triggers outlined in the NER.

Strategic reserves would differ from reserves procured under the RERT function under Rule 3.20 of the NER. Under the RERT framework, AEMO can procure short-, medium- or long-notice reserves. AEMO procures long-notice reserves up to 12 months ahead to meet shortfalls against the reliability standard for the NEM as projected in the Electricity Statement of Opportunities (ESOO). In contrast, strategic reserves would be procured for a multi-year timeframe to meet jurisdictional reliability preferences greater than the NEM reliability standard. The strategic reserves service would therefore be longer-term and more tailored to covering very-low-likelihood but very-high-consequence events.

Several stakeholders have suggested strategic reserves as a useful addition to the NEM.

> *Strategic reserves could present an avenue to increase reliability, with limited impact on the market dynamics and prices. If, like the [Reliability and Emergency Reserve Trader], strategic reserves were explicitly (and only) out-of-market, and don't impact price formation within the market, it may present an option with limited distortion of the wholesale market dynamics.* **– University of New South Wales Collaboration on Energy and Environmental Markets**[431]
>
> *...the current energy-only market design can provide enduring market signals and certainty ... when complemented by: ... a strategic reserve.* **– Nexa Advisory**[432]

5.24 Existing reserves have been focused on the short term

Reserves in the NEM today are primarily procured through the RERT framework. The framework directs AEMO to take reasonable actions to contract for emergency reserves in accordance with guidelines in the NER set by the Reliability Panel. RERT is triggered when AEMO projects a breach of the reliability standard – that is, 0.002% of electricity demand is likely to be unserved over the course of a year. Once triggered, RERT allows AEMO to procure reserve services for a period of up to 12 months.[433]

Interim Reliability Reserves (IRR) were introduced as a temporary measure in 2020. They were originally set to expire in 2025, but the AEMC extended the application of the measure to 2028.[434] [435] The AEMC established an out-of-market reserve which was used to support the more stringent Interim Reliability Measure (IRM) (0.0006%). This provision allowed AEMO to procure reserve services for up to three years.[436] In practice, the longest contract supported through the IRM has been four months.[437]

Jurisdictions have used temporary derogations to modify these rules when managing local circumstances. Victoria allowed AEMO to enter into reserve contracts for up to three years between 2019 and 2023. South Australia recently had a derogation allowing the use of recently mothballed gas generators to support RERT contracts.

5.25 Longer-term strategic reserves could help jurisdictions manage emerging risks

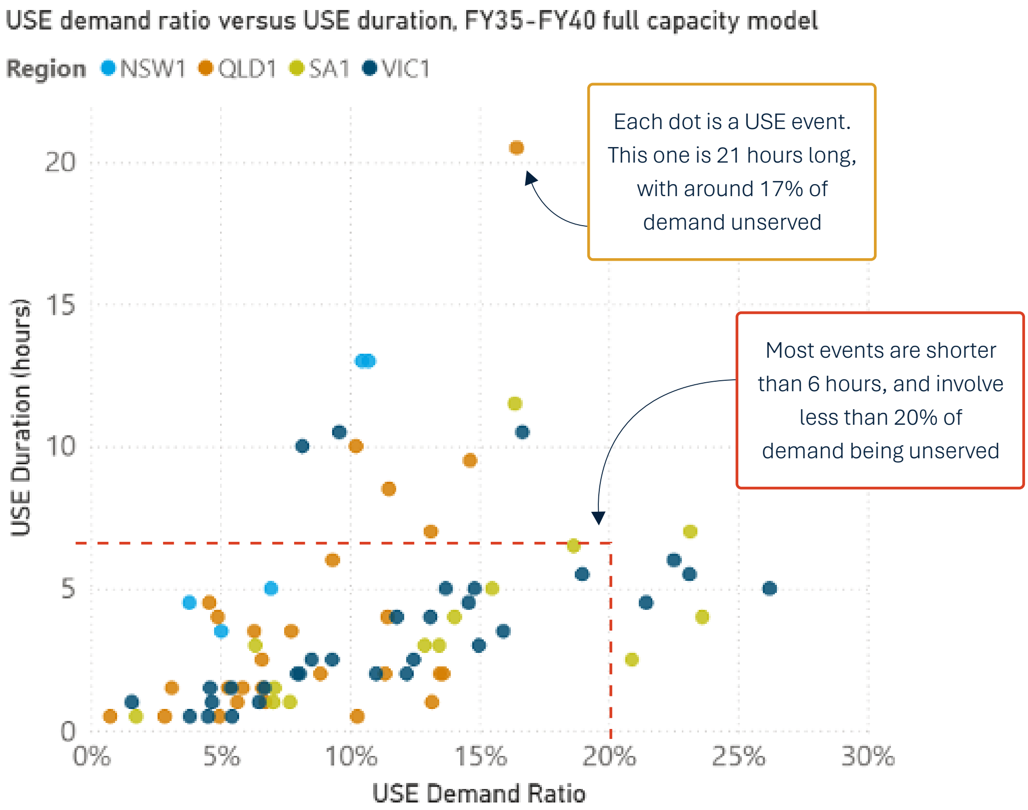
As outlined in **Chapter 2: Trends and challenges in the NEM** and **Chapter 3: Ensuring effective operation of the spot market**, one of the changes occurring in the electricity system is increasing weather-dependency of both supply and demand. Approaches to managing reliability will need to evolve in parallel with the transition of the electricity system. For example, future supply and demand imbalances are likely to shift from short duration peak demand in summer to extended periods of energy deficit in winter.

431 UNSW CEEM (2025), Submission to the Initial NEM Review consultation, p 9.
432 Nexa Advisory (2025), Submission to the Initial NEM Review consultation, p 2.
433 AEMO (2024), Reliability and Emergency Reserve Trader (RERT).
434 AEMC (2023), National Electricity Amendment (Extending the application of the IRM to the RRO) Rule 2023 No. 4.
435 The cut-off date for entering into multi-year contracts under the IRR was 31 March 2025, meaning that AEMO can now only enter into reserve contracts in line with long-notice RERT.
436 DCCEEW (2020), Interim Reliability Measures.
437 AEMO (2023, 2024, 2025), RERT Reporting.

The Reliability Panel considers long-term weather variability when reviewing the reliability standard and market price settings and recently conducted extensive modelling of a large number of possible outcomes to examine future weather variability in depth.[438] The Panel recommends market price settings continue to be the primary signal of the value of meeting reliability standards. Procurement quantities for the ESEM will be based on sufficient bulk energy, shaping and firming to meet the reliability standard, including consideration of weather variability. The combined actions of the Reliability Panel and ESEM should support meeting the reliability standard across most future expected variations in weather.

However, as noted by the Reliability Panel, these mechanisms cannot completely eliminate the risk of energy shortfalls, and it is possible that when events do occur they may be deeper or longer in duration (but still very rare – see Figure 63). Jurisdictions may want to procure additional insurance beyond the reliability standard to protect against such events.

Figure 63 – Unserved energy events (USE) in a possible future NEM



Source: Figure 6.3 from Reliability Panel (2024), Review of the form of the reliability standard and administered price cap, p. 30.

New resources required to cover high-impact, low-probability events are unlikely to recover the costs of their investment in-market unless market price settings are raised to extremely high levels. Put simply, if the cost of the resource needs to be recovered via a small number of hours every few years, the price would need to be extraordinarily high. This is likely to be unacceptable to stakeholders and not in the long-term interests of consumers. As such, an out-of-market strategic reserves service is

[438] Reliability Panel AEMC (2024), Review of the form of the reliability standard and administered price cap, p 20.

a more appropriate mechanism to encourage the establishment of the necessary resources to cover these rare weather-driven events.

How the strategic reserves service would work – at a glance

1. **Establish the need for reserves:** The Reliability Panel would assess the costs and benefits of procuring additional out-of-market reserves and provide advice to jurisdictions, with this advice to be published. This advice would consider the likelihood and severity of potential reliability shortfalls, the nature of high-impact, low-probability events, and the trade-off between cost and reliability. The Reliability Panel's analysis would be informed by measures such as the value of customer reliability, value of customer resilience, and jurisdictional reliability standards.
2. **Nominate the level of reserves:** Informed by the Reliability Panel's advice, jurisdictions would determine if any strategic reserves should be procured. Jurisdictions may also consider locational diversity of reserves to improve climate resilience and mitigate risks from localised disruptions.
3. **Procure reserve contracts:** Reserves would be secured alongside the ESEM and contracted on a long-term basis. Proponents would be able to provide multiple services where cost-effective. In addition to the provision of shaping and firming, a project could provide reserves with the right adjustments to project design, and constraints on how the project is operated. The incremental cost of adding reserve capability is likely to be lower than building stand-alone reserves. For example, a pumped hydro project could expand its storage duration, holding the additional capacity in reserve, or a gas-fired generator could contract for additional on-site fuel storage to enhance its reserve capacity. Reserve contracts would be bespoke and physically linked to specific projects (i.e. not fungible).
4. **Recover costs (ongoing):** The cost of the contracts would be recovered from consumers within the jurisdiction that requested the reserves.
5. **Trigger reserve contracts:** Contracted projects would be required to remain available to mitigate potential reliability shortfalls and would face penalties if unavailable when called upon. The triggers for deployment would be clearly defined in the regulatory framework.

Further details on the strategic reserves service are available in section 6.1 of the **Supplementary Materials**.

Stakeholder feedback on strategic reserves

Feedback broadly supported the inclusion of a strategic reserve service. Key points included:

Demand-side participation: Some stakeholders raised the importance of ensuring demand-side options could provide strategic reserves services.[439] The Panel considers its proposed design would enable demand-side options to provide strategic reserves.

Alignment with coal exits: Some stakeholders suggested aligning strategic reserves with the timing of coal closures,[440] with Iberdrola suggesting reserves be used as a 'waiting room' for new capacity to enter upon coal closure.[441] The Panel considers the Reliability Panel would consider the impacts of anticipated coal exits when advising jurisdictional governments on reliability forecasts and trade-offs. Jurisdictional energy ministers would therefore account for anticipated coal closures before directing the ESEM Administrator to procure strategic reserves. To be clear, jurisdictions could utilise the reserve service to address concerns about unanticipated coal exit should they believe it is necessary.

Interaction with market price settings: Several stakeholders raised that the interaction between strategic reserves and market price settings should be considered. Some stakeholders suggested the Reliability Panel consider the strategic reserves service when reviewing the market price settings.[442] The AEMC raised that strategic reserves should only target events that market price settings do not manage well.[443] Some stakeholders also identified the importance of the market price cap, including that strategic reserves should only bid to enter the market at the cap.[444] The Panel notes this feedback and has retained its core recommendation that strategic reserves would only ever be dispatched as an alternative to load shedding.

Emissions reduction objective: Some stakeholders raised the importance of considering emissions when procuring strategic reserves,[445] with the Investor Group on Climate Change warning that strategic reserves could incentivise gas peakers over long duration storage.[446] The reserves service would be allocated to the cheapest provider of that service. The Panel has made relevant adjacent recommendations in relation to emissions and firming generation (**Recommendation 11A** and **Recommendation 11B**).

Inter-jurisdictional considerations: Some stakeholders suggested considering the inter-jurisdictional benefits of strategic reserves services or NEM-wide procurement.[447] The Panel considers the strategic reserve service could support projects with interjurisdictional benefits in multiple ways. For example, if multiple jurisdictions request the ESEM procure strategic reserves, those jurisdictions could agree to share the costs of mutually beneficial investments. Even if only one jurisdiction procured strategic reserves from a project with interjurisdictional benefits, the project could also value stack by providing firming services in multiple regions.

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[439] Submissions to the NEM Review Draft Report consultation) from BlueScope, Climateworks Centre and S. Coates.
[440] Submissions to the NEM Review Draft Report consultation from IEEFA and Nexa Advisory.
[441] Iberdrola (2025), Submission to the NEM Review Draft Report consultation, p 3–4.
[442] Submissions to the NEM Review Draft Report consultation from IEEFA and EUAA.
[443] AEMC (2025), Submission to the NEM Review Draft Report consultation, p 29.
[444] Submissions to the NEM Review Draft Report consultation) from EnergyAustralia and CEIG.
[445] Submissions to the NEM Review Draft Report consultation from CEIG, IEEFA and APGA.
[446] Investor Group on Climate Change (2025), Submission to the NEM Review Draft Report consultation, p 6.
[447] Submissions to the NEM Review Draft Report consultation from Eku, Tasmanian Government (Minister Duigan), Hydro Tasmania and LDES Council.

Recommendation 11: Governments and market bodies in the NEM should pursue a coordinated suite of reforms to ensure regulatory settings, the innovation ecosystem and existing policies and programs are aligned with the ESEM

The Panel recognises that the success of the proposed ESEM will depend not only on its design but also on the broader regulatory, policy and institutional environment. A well-functioning long-term investment mechanism should be supported by consistent market signals, complementary policy frameworks and a clear pathway for integrating new technologies. Without alignment across these domains, the ESEM's ability to unlock timely and efficient investment in bulk energy, firming and shaping could be undermined.

To this end, the Panel has identified a coordinated set of supporting reforms that governments, energy ministers and market bodies should pursue. These reforms are designed to ensure electricity sector emissions targets are applied consistently, innovation is strategically directed, existing schemes contribute to market functioning and market settings allow participants to manage risk. They also highlight opportunities to streamline planning and improve regulatory clarity as new resources enter the system.

Together, these actions would reinforce investor confidence, lower emissions, improve competition and unlock the full potential of the ESEM.

Recommendation 11A: Governments should clarify how their greenhouse gas emissions targets apply to projects procured to provide firming services, to provide certainty for investors

Zero-emissions bulk energy and shaping providers supported by the ESEM would help to decarbonise the NEM, as the providers of these services would not produce emissions. However, peaking thermal generators that obtain firming contracts would produce scope 1 emissions if fuelled with conventional methane or diesel. As firming generators do not have high capacity factors, total emissions from firming would be relatively low even if it is provided by conventional peaking gas generation in the short term.

With a conventional cap contract or similar, an emissions-intensive firming project would be fully exposed to uncertain costs associated with changes in emissions policy. This risk has already impacted appetite for firming investment[448] [449] and will continue to do so in the absence of a clear framework for how emissions are considered for firming generation.

Several energy generation investors have indicated to the Panel that clarity in relation to emissions targets from firming generation would be a pre-requisite for future investment. The Panel notes that some governments have provided this clarity, and examples include:

- **Requiring offsets for scope 1 emissions:** New South Wales has provided a clear framework through regulation by the state's Environment Protection Authority. New gas generators must have an annual emissions intensity lower than the state average prior to 2036. After that, projects must achieve net zero scope 1 emissions with emission offsets sourced from within the state.[450]
- **Setting emissions intensity thresholds:** Western Australia is exploring options for setting an emissions intensity threshold for capacity credit eligibility[451] and Europe introduced a limit to the scope 1 emissions intensity of generators for its capacity scheme.[452]

Stakeholder feedback on inclusion of emissions targets for firming services

Relevant stakeholders broadly supported this recommendation.[453] APGA noted that clarity on the treatment of emissions would be useful under the Safeguard Mechanism and future emissions reduction schemes.[454] Some submissions made proposals that could be complementary to the ESEM. For example, the Justice and Equity Centre's submission suggested that governments could require any new gas plant to have emissions intensity

448 Comincioli et al. (2024), 'Carbon Taxation and Electricity Price Dynamics: Empirical Evidence from the Australian Market', in Environmental and Resource Economics.
449 Carbon policy uncertainty was also raised in many submissions to the NEM Review Initial consultation.
450 NSW EPA (2024), Overseeing firming infrastructure's greenhouse gas emissions obligations.
451 WA Government (2024), Market Advisory Committee - March 2024 - Meeting papers.
452 European Union (2019), Regulation - 2019/943 – on the internal market for electricity, Article 22-4.
453 Submissions to the NEM Review Draft Report consultation from Akaysha, APGA, Fluence, Justice and Equity Centre, Origin and the Productivity Commission.
454 APGA (2025), Submission to the NEM Review Draft Report consultation, p 24.

limits, emissions offsets and hydrogen-readiness requirements.[455] The Panel considers if jurisdictional governments set such requirements, they could feature as eligibility requirements for participating in the ESEM. Similarly, recent work from the Grattan Institute recommended reactivating the Safeguard Mechanism in the electricity sector.[456] Approaches such as these would complement the ESEM and assist in delivering the Panel's recommendation to provide clarity on firming emissions requirements.

Recommendation 11B: The Australian Government should task ARENA, in collaboration with the CEFC and other financiers, to accelerate the development and deployment of zero emissions technologies that provide firming at scale

Firming is a crucial service to ensure the reliability of the electricity system as it moves to an increasingly weather-dependent state. Zero emissions technologies like long-duration lithium-ion energy storage, compressed air storage, iron air or flow batteries, pumped hydro, hydrogen turbines and engines, small-scale aggregated demand response or industrial demand response can already provide this service. However, these technologies are often not yet as cost-competitive as fossil fuel alternatives, such as open-cycle gas turbines and gas-fuelled reciprocating engines.[457]

Considering current technology costs, AEMO's 2024 ISP suggests the NEM will need around 15 GW of low capacity factor peaking gas generation.[458] The use of some gas generation will support rapid and substantial emissions reductions by allowing the closure of ageing, high-emissions coal plants, reducing NEM emissions from more than 100 million tonnes today to less than 10 million tonnes in future.[459] Nonetheless, these remaining emissions are material. Stakeholders have also noted that an over-reliance on gas into the future could create risks if gas supplies are limited or unreliable.[460]

For these reasons among others, efforts to develop suitable replacement technologies should be prioritised. The benefits of zero emissions firming technologies were noted in stakeholder submissions, as were the commercial challenges they face:

> *Adding [long duration energy storage (LDES)] to the system can have a material positive impact on both emissions and system costs … Challenges bringing LDES include revenue uncertainty, market design, large upfront capital investment and the early development stage of many LDES technologies.* **– Advanced Material and Battery Council**[461]

[455] Justice and Equity Centre (2025), Submission to the NEM Review Draft Report consultation, p 14.
[456] Grattan Institute (2025), Bills down, emissions down: A practical path to net-zero electricity, p 14, 25.
[457] CSIRO (2024), GenCost 2024–25 Consultation Draft.
[458] AEMO (2024), 2024 Integrated System Plan, p 69.
[459] AEMO (2024), Integrated System Plan Generation and Storage Outlook, Step Change Scenario.
[460] CEC (2024), The future of long duration energy storage, p 9.
[461] Advanced Material and Battery Council (2025), Submission to the Initial NEM Review consultation, p 4.

> *The NEM Review Panel should recommend immediate government attention to fund the gap and develop programs that incentivise investment in LDES technologies that are scalable such as flow batteries and liquid air storage.* **– Nexa Advisory**[462]
>
> *The funding allocation and mandate should recognise that grid scale solutions can be capitally intensive initially but are essential to enable the retirement of the 'last mile' of thermal generation, resulting in a grid that is reliable, resilient, zero carbon and shielded from international fuel shocks.* **– Raygen**[463]

ARENA, working with the CEFC and other financiers, is well placed to support the accelerated development and deployment of zero-emissions technologies. ARENA and the CEFC have worked together effectively in other sectors, including large-scale solar, to create mutually complementary grant and loan products to crowd in private sector capital.[464]

ARENA's Large-scale Solar PV Competitive Round[465] demonstrated that targeted support could further progress cost reduction in utility scale photovoltaics. ARENA has similarly supported pumped hydro[466] and compressed air storage projects[467], helping to bridge the gap to progress towards commercial operation in the NEM. Increased ARENA and CEFC support for zero emissions firming technologies should further accelerate NEM decarbonisation and help to remove the last source of emissions from Australia's electricity system.

> *The importance and value of innovation is clearly demonstrated by the enormous influence of new technologies over the last 10 years (e.g. wind, solar and lithium-ion batteries). Without clear commercialisation pathways for emerging technologies, Australia will miss innovation opportunities and the associated economic and societal benefits.* **– ARENA**[468]
>
> *Near-term investment opportunities in LDES remain limited, with the commercial case for projects with storage capacity durations beyond four hours remaining challenging. Projects that progress will likely require some form of revenue support or government intervention to have a viable route to market. Even LDES projects with revenue support may face significant other risks including geotechnical or first-of-a-kind technical applications in the complex Australian grid. The CEFC is working with public and private sector stakeholders on a financing offering to support these projects.* **– CEFC**[469]

[462] Nexa Advisory (2025), Submission to the Initial NEM Review consultation, p 6.
[463] Raygen (2025), Submission to the NEM Review Draft Report consultation, p 3.
[464] ARENA (2025), Submission to the NEM Review Draft Report consultation, p 4.
[465] ARENA (2018), Large-Scale Solar Round.
[466] ARENA (2021), Kidston Pumped Hydro Energy Storage.
[467] ARENA (2022), Hydrostor - Broken Hill Advanced Compressed Air Energy Storage Demonstration.
[468] ARENA (2025), Submission to the NEM Review Draft Report consultation, p 5.
[469] CEFC (2025), Submission to the NEM Review Draft Report consultation, p 3.

Recommendation 11C: Governments overseeing existing generation underwriting schemes to support long-term investment should consider options to improve derivative market liquidity

Federal, state and territory governments have introduced schemes to provide long-term revenue support for new capacity in the NEM, including:

- Australia Capital Territory Renewable Energy Reverse Auctions
- Victorian Renewable Energy Target (VRET)
- New South Wales Electricity Infrastructure Roadmap, in particular the LTESA contracts
- South Australian FERM
- The Australian Government CIS.

A major focus of these schemes has been to manage generator investment uncertainty by incentivising new renewable energy, storage and firming capacity. However, stakeholders have identified that the design or implementation of these schemes may decrease derivatives market liquidity.

While some schemes, such as the VRET and LTESA, include recycling provisions their use remains nascent.[470] In its submission to the Draft Report, Origin recognised the importance of retaining the incentives established in government schemes for participants to offer contracts.[471]

> *The contractual requirements of the CIS, and equivalent state schemes, have greatly limited the ability of new assets to participate in the financial market, which has reduced their ability to contribute to market liquidity.* **– AFMA**[472]
>
> *Both the Roadmap and CIS schemes are currently struggling with how to accommodate related party contracting.* **– RWE Renewables**[473]
>
> *The CIS will also reduce the participation in the contracts market, which could cause liquidity problems.* **– AEC**[474]

[470] For example, SEC Victoria (2025), SEC to power 5% of Victoria's electricity market, and provisions in New South Wales Electricity Infrastructure Investment Act 2020, Section 52.
[471] Origin (2025), Submission to the NEM Review Draft Report consultation, p 19.
[472] AFMA (2025), Submission to the Initial NEM Review consultation, p 6.
[473] RWE Renewables (2025), Submission to the Initial NEM Review consultation, p 3.
[474] AEC (2025), Submission to the Initial NEM Review consultation, p 3.

Stakeholder feedback on using existing schemes to improve derivative market liquidity

Stakeholders broadly agreed with recycling government-supported contracts to support market liquidity.[475]

Some stakeholders noted support was contingent on recycling mechanisms being carefully designed, including by ensuring transparency to avoid distortions.[476] For example, Enel X cautioned against governments becoming traders.[477] The Panel's position is that contract recycling mechanisms should be carefully designed and governments should not seek to influence the market through trading strategically. The Panel considers that the benefits of improved market liquidity would outweigh these risks, which can be controlled for and mitigated. For example, the Panel's recommended ESEM design would require the ESEM Administrator to sell down contracts in a structured, transparent and predictable manner in accordance with an established risk management framework.

EDF Australia suggested that government schemes could recycle legacy contracts into the ESEM to support market liquidity.[478] The Panel considers recycling and contract novation (where appropriate) could have significant benefits for broader market liquidity and should be considered.

Recommendation 11D: The AEMC should review interconnector hedging arrangements to improve long-term certainty. For example, this could include options to the effect of extending the timeframe for inter-regional settlement residue units beyond three years.

Stronger inter-regional hedging is likely to be needed to support investment in bulk energy, shaping and firming. The Panel supports the AEMC's commitment to review inter-regional settlement and hedging arrangements, which are essential in a system increasingly reliant on bulk energy, shaping and firming where sharper regional price differentials are expected.[479] The AEMC's review will aim to strengthen inter-regional trade, ensure fair cost distribution and maintain confidence in the NEM's market mechanisms.

As part of its review, the Panel recommends the AEMC review hedging arrangements across interconnectors to provide longer-term certainty. In particular, the AEMC should consider options that would extend the contracting tenor of inter-regional settlement residue (IRSR) units beyond three years. This would improve the value of the settlement residue auction process as a financial

475 Submissions to the NEM Review Draft Report (2025) from EDF Australia, Fluence, Origin and the Smart Energy Council.
476 Smart Energy Council (2025), Submission to the NEM Review Draft Report consultation, p 12.
477 Enel X (2025), Submission to the NEM Review Draft Report consultation, p 19.
478 EDF Australia (2025), Submission to the NEM Review Draft Report consultation, p 19.
479 AEMC (2025), Rule determination: National electricity amendment (Inter-regional settlements residue arrangements for transmission loops) Rule 2025, p 65.

risk management tool, particularly when used alongside contracts issued under the ESEM. Several stakeholders supported extending the tenor of interconnector contracts.[480]

> *Longer-term interconnector contracts could strengthen cross-border risk management and support regional investment.* **– EDF Australia**[481]
>
> *IRSRs should be auctioned further in advance (5 years) with new procurement options and improved liquidity in secondary market trading to increase competition and hedging options.* **– Hydro Tasmania**[482]

This recommendation would complement initiatives and reforms already underway to support interconnection across the NEM. Some of these relate directly to interconnectors (below).

Interconnectors

Interconnectors are critical to delivering the full benefits of the NEM, particularly as more weather-dependent generation is connected. Their importance will continue to grow as interconnectors link regions with diverse weather patterns.

One barrier to interconnector investment has been the allocation of costs across interconnected regions. While the benefits of interconnection are often broad and diffuse, the construction costs typically fall on one or two jurisdictions, creating a misalignment of costs and benefits.

Even where interconnector costs are shared equally between jurisdictions, there can still be disparities in the cost-benefit ratio for each, often reflecting differences in population size and how those costs are recovered from consumers.

This barrier should now be reduced following a recent NER change that allows jurisdictions to agree on cost allocation through ministerial agreement.[483] Where further work is required on interconnector cost sharing, governments and the AEMC should continue to pursue it.

The Panel acknowledges that several stakeholders raised concerns with the AEMC proposing to net off positive and negative IRSRs as part of its inter-regional settlements residue arrangements for transmission loops rule change.[484] The AEMC's recent rule change process highlights the value in having a holistic review of inter-regional settlement and hedging arrangements. The Panel recommends the AEMC prioritise its review of inter-regional settlement and hedging arrangements given these arrangements will become more critical.

[480] For example, SEC, Submission to the NEM Review Draft Report consultation, p 12.
[481] EDF Australia (2025), Submission to the NEM Review Draft Report consultation, p 20.
[482] Hydro Tasmania (2025), Submission to the NEM Review Draft Report consultation, p 7.
[483] AEMC (2024), Providing flexibility in the allocation of interconnector costs.
[484] Submissions to the NEM Review Draft Report consultation from AFMA, EnergyAustralia, Origin and Snowy Hydro.

Recommendation 11E: Once energy ministers are satisfied the ESEM and MMO are working effectively they should phase out the Retailer Reliability Obligation (RRO)

The RRO commenced on 1 July 2019 and requires retailers to establish firm contractual coverage when AEMO foresees a potential shortfall in energy supply, with the aim of incentivising investment in new capacity. While the Panel supports the rationale that led to the establishment of the RRO, a range of implementation issues have limited the scheme's effectiveness and imposed costs or created uncertainty for a breadth of market participants.

As the RRO only requires retailers to contract for the near term, it does not address the tenor gap and is therefore not suited to driving new investment to ensure long-term reliability. Once established, the ESEM should fulfil the intended purpose of the RRO in this respect.

While market participants raised significant concerns with the RRO, many participants agreed a market making scheme similar to the Market Liquidity Obligation (MLO, a sub-component of the RRO) could be a valuable component of the future NEM.[485] **Recommendation 6** includes the establishment of a permanent MMO in the NEM.

Stakeholder submissions strongly agreed with phasing out the RRO, with most advocating for a more immediate repeal than suggested in the Draft Report.[486]

> *The requirement to contract through the RRO is cumbersome, expensive and does not achieve the RRO's intended outcomes.* **– Flow Power**[487]
>
> *The RRO does not incentivise investment and should be abolished.*
> **– Shevy Moss Feiglin & Tom Geiser**[488]
>
> *The RRO is unlikely to promote investment, given it is a reactive scheme that has rarely been triggered … There is also a weak relationship between the typical cause of a forecast reliability gap (P10 demand coincident with outages) and the actions that retailers are required to take (temporarily entering financial contracts to a P50 level).* **– AEMO**[489]
>
> *We think it is important that the RRO is repealed when the ESEM and MMO are introduced as the ESEM will remove any need for the RRO to send investment signals and it will be much simpler for the new MMO to start operating if there is no prospect that RRO's similar Market Liquidity Obligation could be triggered in parallel to it.* **– AFMA**[490]

The Panel considers there could be several advantages of aligning the phase out of the RRO with the ESEM and MMO's introduction. These would include removing regulatory uncertainty and avoiding potential duplication. Shell considered there to be a risk that the RRO would remain in place without

[485] Examples from the NEM Review Initial NEM Review consultation include the AEC, AFMA, AEMC and the CEC.
[486] Submissions to the NEM Review Draft Report consultation from AEMC, AFMA, Flow Power, Fluence, Origin, Shell and Tesla.
[487] Flow Power (2025), Submission to the Initial NEM Review consultation, p 9.
[488] Shevy Moss Feiglin & Tom Geiser (2025), Submission to the Initial NEM Review consultation, p 2.
[489] AEMO (2025), Submission to the Initial NEM Review consultation, p 7.
[490] AFMA (2025), Submission to the NEM Review Draft Report consultation, p 6.

commitment to a repeal date,[491] and Flow Power considered it would be more administratively efficient to remove it alongside the ESEM regulatory reforms.[492] The AEMC considered it could take some time before energy ministers have sufficient certainty to consider phasing out the RRO but noted that NEL amendments could be made to reduce some of the current regulatory burden placed on participants.[493]

The Panel considers that there would be value in pursuing the RRO's phase-out when progressing ESEM and MMO legislation by including a trigger for energy ministers to repeal the relevant provisions.

Recommendation 11F: Once the ESEM framework is established, energy ministers should consider opportunities to rationalise NEM forecasting and planning documents to avoid inconsistencies and duplication

Once ESEM planning processes are established, it will be important to clearly delineate the roles of existing planning and reporting exercises. This would minimise the risk that multiple conflicting planning pathways create uncertainty for participants on the direction of the future NEM.

Several planning exercises currently exist in the NEM and elsewhere; each has its own role in informing the mix of services required in the future.

Table 6 – Existing planning exercises in the NEM

Planning exercise	Purpose and process	Frequency and horizon
ISP (AEMO)	Develop an efficient whole-of-system plan that achieves power system needs and contributes to the NEO. Specify network projects as actionable to accelerate regulatory processes.	Published every two years, after consultation, technical inputs and modelling. 25+-year indicative pathway.
ESOO (AEMO)	Reveal possible opportunities for new investment to fill gaps. Assess reliability to determine whether the Retailer Reliability Obligation should be triggered.	Published annually (or after material change to system). 10-year detailed outlook.
New South Wales Infrastructure Investment Objectives Report (ASL)	Identify the most cost-effective path to meet New South Wales Electricity Infrastructure Roadmap goals, including generation and long-duration storage targets, the Energy Security Target and NEM reliability standard. Informs LTESA tenders.	Published every two years, or as required if firming needed to avoid Energy Security Target breach. 20-year indicative pathway. 10-year plan for tenders.

Pending broader questions around ESEM governance and implementation, there may be opportunities to reconcile ESEM planning and existing processes, including the ISP and ESOO. The goals and underpinnings of these exercises have changed and expanded significantly over time. As the ESEM is

[491] Shell (2025), Submission to the NEM Review Draft Report consultation, p 6.
[492] Flow Power (2025), Submission to the NEM Review Draft Report consultation, p 9.
[493] AEMC (2025), Submission to the NEM Review Draft Report consultation, p 31.

established, it is appropriate to consider whether some of the roles of these planning exercises could be dovetailed with those underpinning ESEM operations.

This recommendation could be incorporated into the ongoing ECMC work to reduce reporting duplication.[494]

Stakeholder feedback on rationalising forecasting and planning documents

Stakeholders provided in-principal support while raising that before documents are rationalised, it would be important to first:

- publish an overview of how consistency across states is likely to be achieved[495]
- consider the impacts on all users of the ISP.[496]

In addition, the AER suggested incorporating future document rationalisation in designing the ESEM framework from the outset. Doing this could also help mitigate potential governance issues arising from functional overlap with existing planning and procurement roles.[497]

The Panel acknowledges that these suggestions would be valuable to consider should its recommendations be implemented.

Recommendation 11G: Energy ministers should pursue reforms to improve consistency in the treatment of load, storage and generators connected at the distribution and transmission level, to ensure a level playing field

The most efficient mix of resources is likely to include both transmission and distribution-connected generators and storage, including at sub-transmission and high-voltage levels. Distribution network service providers (DNSPs) have suggested that there is capacity to connect these resources at some locations on distribution networks with little requirement for network augmentation. Analysis by LEK for ENA, for example, suggested connection at these locations is cheaper (per MW) than connecting to transmission in a Renewable Energy Zone.[498]

> *Our network includes high-voltage sub-transmission assets with spare latent capacity that could efficiently host utility scale batteries or flexible loads, reducing the need for potentially more costly transmission upgrades and new transmission build. If efficiently leveraged, this latent capacity could significantly contribute to the energy transition.* **– Essential Energy**[499]

[494] ECMC (2025), Communique 14 March 2025, p 2.
[495] Akaysha (2025), Submission to the NEM Review Draft Report consultation, p 17.
[496] Climateworks (2025), Submission to the NEM Review Draft Report consultation, p 10.
[497] AER, Submission to the NEM Review Draft Report consultation, p 7.
[498] ENA and LEK (2024), The Time is Now: Getting smarter with the grid, p 23.
[499] Essential Energy, Submission to the NEM Review Draft Report consultation, p 2.

Storage providers have reported limited success in negotiating access to distribution networks on terms competitive with those available on the transmission network. Transmission network and distribution network connection and pricing are regulated under different parts of the NER. To the extent the rules and their implementation by network businesses result in different pricing and service levels that do not reflect different underlying cost drivers, there is an inefficient signal for investment.

This issue was identified and partly considered in the AEMC's Integrating Storage rule-change process in 2020 to 2021.[500] In its final determination, the AEMC retained the current framework to allow storage to connect under a:

- negotiated agreement at the transmission level
- direct control service tariff or storage tariff trial option, where offered, at the distribution level.

The AEMC made minor amendments to the NER to clarify how the negotiated framework applies in relation to grid-scale storage and hybrids, and to reduce barriers to the uptake of shared transmission services on a negotiated basis.

The AEMC noted "the rules were not designed for loads like storage that are price sensitive and can minimise impact on network congestion. It would be appropriate for a future rule change to address the broader issue of how network costs should be recovered".[501] The AEMC noted that these issues are also relevant for other large flexible loads (e.g. hydrogen, data centres). At the time, the AEMC anticipated receiving a rule-change request covering this issue, but this request did not eventuate.[502] The AEMC's pricing review is an avenue to consider distribution network reforms in this area, but its current scope does not appear to allow for examining differences between transmission and distribution holistically.[503]

While the Panel has not formed a view on the appropriate solution in this area, it notes several types of solutions have been raised by stakeholders in the Panel's initial investigation of the area:

- Establish 'local energy hub' arrangements allowing DNSPs to make prospective investments to support future generation and storage connection (with appropriate regulatory oversight to ensure prospective expenditure is efficient). Essential Energy supported this solution as a means to facilitate rapid connection of renewable generation, storage or potentially data centres.[504]
- Allow negotiated arrangements at distribution level (noting this would need to come with appropriate incentives to balance the relative market power of distribution networks in such a negotiation). Raygen supported this solution, noting that without tariff flexibility, it can be challenging to make an investment case for distribution-level connections, which is a missed opportunity to enable greater penetration renewables into the grid.[505]
- Reform tariff frameworks so battery energy storage systems and utility-scale responsive loads receive tariffs which better reflect their ability to reduce network costs over time and remove the burden of individually negotiating each connection. ARENA supported using network tariff

[500] AEMC (2021), Integrating energy storage systems into the NEM.
[501] Op Cit., p xi.
[502] Op Cit., p 53.
[503] AEMC (2025), The pricing review: Electricity pricing for a consumer-driven future.
[504] Essential Energy (2025), Submission to the NEM Review Draft Report consultation, p 2.
[505] Raygen (2025), Submission to the NEM Review Draft Report consultation, p 3.

reforms to level the playing field and suggested the AEMC could action this solution through its current pricing review.[506]

- Reform connection and charging arrangements, looking across transmission and distribution rules. SA Power Networks supported this solution, noting that providers are more able to negotiate and receive preferential charging arrangements based on resource flexibility when connecting on transmission networks.[507]

The Panel recommends energy ministers pursue solutions in one or more of these areas by tasking the AEMC with a review, or through a rule-change request, which could allow faster resolution within the AEMC's decision-making powers. Relevant stakeholders supported this recommendation.[508]

[506] ARENA (2025), Submission to the NEM Review Draft Report consultation, p 5.
[507] SAPN (2025), Submission to the NEM Review Draft Report consultation, p 4.
[508] See Submissions to the NEM Review Draft Report consultation from DNSPs (Ausgrid, Ergon, Energex, Essential Energy and SAPN) as well as ARENA, Origin, the Productivity Commission, RayGen and Tesla.

Recommendation 12: Jurisdictions should implement this package of reforms expeditiously, ensuring market bodies are suitably resourced to undertake implementation activities concurrently with legislative processes

The Panel recommends that energy ministers implement this package of reforms, with a particular focus on the MMO, ESEM and reforms to increase the visibility of price-responsive resources, as soon as possible.

The Panel has identified a pathway which would enable the ESEM to be piloted by the end of 2026 and formally commenced by the start of 2027 to minimise any gap following the conclusion of the CIS (see Implementation Roadmap at **Supplementary Materials**). This timeframe would require coordinated effort across governments and market bodies, with several workstreams proceeding in parallel.

Coordination would be a substantial exercise, with several co-dependent workstreams requiring strong program management. To support successful and timely implementation, the Panel recommends energy ministers:

- **Leverage the expertise and institutional capability within existing market bodies.** This approach recognises that the ESEM represents an evolution from the CIS, LTESA and SA FERM frameworks. This is a key design feature, adopted by the Panel using the existing policy and regulatory architecture rather than 'reinventing the wheel'.
- **Adopt interim governance arrangements where needed to accelerate delivery.** Given the Panel anticipates that legislative reform would take up to a year, substantial work would need to be progressed in tandem to minimise any gap between the operation of the ESEM and the CIS. This work would include establishing the ESEM Administrator, a role that would be given post-dated authority once legislation is passed. The Panel recommends appointing an interim ESEM Administrator (for example, ASL) while enduring arrangements are developed. This could help provide the market with more immediate certainty and facilitate a more orderly transition.
- **Ensure relevant entities are suitably resourced to progress work.** While the Panel's recommendations allow for in-market cost-recovery, some parties could be reluctant or unable to expend resources in fulfilling roles that are yet to be legislated. The most suitable funding path would depend on the entity. For example, recommendations that would create or expand responsibilities for the AER should receive adequate and timely funding from the Australian Government.
- **Maintain an open, industry-facing approach to implementation.** This could include leveraging the consultation model and forums used during the NEM Review, including regular, transparent

engagement with peak bodies, industry representatives, and consumers through structured forums and weekly consultation meetings.[509]

- **Establish clear accountability for delivering the reforms.** This could be achieved by appointing a senior leader to chair the ECMC working group to oversee and coordinate the package of legislative reforms (covering **Recommendations 2**, **6**, **7**, **9** and **10**) and act as the primary point of contact for industry. This leader should bring strong energy-market expertise, a strong stakeholder network and a demonstrated commitment to open and transparent engagement with buyers, sellers, governments and market bodies. They should also be able to identify where compromise is needed and broker solutions that preserve the integrity of the overall reform package. The role should have clear reporting lines to the ECMC working group and to energy ministers, while remaining independent of any single NEM jurisdiction. The leader should also bring strong program management capability to ensure coherent and timely delivery across the various workstreams.

[509] Throughout the second half of 202 the NEM Review Panel met weekly with industry peak bodies and market bodies to seek insights and provide regular progress updates. Contract co-design forums were held to help develop derivative contracts and online MMO forums supported key design considerations of the MMO. Details of these meetings are outlined in **Appendix B – Stakeholder engagement**.

6

Ensuring consumers benefit

Chapter summary

The NEM only exists as a construct to serve the long-term interests of consumers. As such, consumer outcomes are a key driver of the Panel's recommendations.

In the previous three chapters, the Panel has put forward a series of recommendations that are intended to safeguard the efficient operation of the energy-only spot market, support transparency, accessibility and liquidity in the derivatives market, and underpin long-term investment in electricity services. The Panel is confident that these recommendations would facilitate outcomes that are in the long-term interests of consumers.

This chapter shifts focus from formal recommendations to observations. These observations highlight how the recommended reforms could unlock broader consumer benefits if complemented by action from governments and market bodies. Feedback provided by stakeholders on these observations following publication of the Draft Report was useful for guiding the Panel's thinking about the interaction of the recommendations with networks and retail markets. The observations presented in this chapter have not changed from those put forward in the Draft Report. However, recommendations in the other chapters have become sharper in their consumer focus due to the feedback provided by stakeholders on these observations that were published in the Draft Report.

The Panel identifies areas where coordinated reforms could amplify the impact of its recommendations and better align the energy market framework with evolving consumer needs. This includes: enabling consumers to access more predictable, simple and stable electricity bills that can mitigate the impacts of price volatility; delivering more equitable network tariffs; and updating consumer protection frameworks for new energy services, including aggregation and virtual power plants (VPPs).

Specifically, the Panel identifies four opportunities for jurisdictions and market bodies considerations that would be facilitated by the Panel's recommendations:

- Support the development of simple, multi-year fixed-price retail contracts by enabling benchmark price transparency and reviewing barriers such as early exit fee restrictions (**Observation 1**). This is facilitated by the market making obligation (MMO) in **Recommendation 6** and the electricity services entry mechanism (ESEM) in **Recommendation 10**.
- Reform network tariff structures to ensure they are more equitable and better aligned with wholesale market dynamics, particularly in the context of rising consumer energy resource (CER) uptake (**Observation 2**). This would unlock the benefits of **Recommendation 2** on price-responsive resources.
- Update the methodology for regulated retail price benchmarks to reflect the evolving nature of the derivatives market in the context of new contract structures and the MMO (**Observation 3**). This would unlock the benefits of **Recommendation 6** to introduce the MMO.
- Extend the National Energy Customer Framework (NECF) to cover new energy services, including CER aggregation, and explore the introduction of an overarching consumer duty to protect customers engaging with more complex service offerings (**Observation 4**). This would ensure consumers can have confidence that **Recommendation 2** on price-responsive resources and **Recommendation 3** on CER integration can be delivered in a way that maximises consumer benefits.

These observations are important directions for future reform. They are presented to inform the ongoing work of jurisdictions, regulators and policy makers, and to ensure that the foundational market reforms proposed in this review are matched by complementary actions to support a simple, fair and consumer-focused energy system.

Observation 1: Consider supporting the development of simple, multi-year fixed-price retail contracts

The Panel has recommended reforms which would improve long-term wholesale price transparency and enable retailers to purchase longer-term wholesale electricity services contracts in the NEM. Retailers would then be well placed to offer multi-year fixed retail offers to those electricity consumers who would value them. This would protect consumers from volatility and deliver more predictable bills.

While some consumers value flexibility, the Panel has heard from a range of stakeholders that most consumers value simplicity, predictability and affordability in their electricity bills. There may be value in, and appetite for, reforms that build on the recommendations put forward by the Panel to better support these consumer preferences for longer-term pricing.

To support these preferences, the Panel observes the following:

- The Australian Energy Regulator (AER) could publish benchmark cost stacks via the Energy Made Easy website, up to five years ahead. These would guide retail offers and help consumers make informed decisions about entering fixed-priced energy contracts that smooth intra- and inter-year volatility.
- Jurisdictions could consider removing regulatory barriers that prevent retailers charging reasonable and cost reflective early exit fees (that reflect the cost to the retailer of hedging risk on behalf of the customer) for consumers who enter into a multi-year contract at a fixed price and then seek to exit the contract before its expiration.

Taken together, these reforms could allow for stable, longer-term prices for consumers that reflect underlying costs, without the volatility and variability associated with an increasingly weather-dependent system.

6.1 Retailers are facing new risks in managing customer load

Retailers play a crucial risk management role in the NEM, ensuring they have adequate bulk energy, shaping and firming resources to meet the demand of their customer portfolios over time. This is typically achieved by purchasing a mix of derivative contracts with electricity generators and, in some cases, use of their own generation resources (vertical integration).

Retail risk management in the NEM is becoming more complex due to rising volatility and variability in the wholesale spot market, driven by several factors including:

- Traditional sources of dispatchable generation are being replaced by weather-dependent generation resources that can experience fluctuations. In some cases, these fluctuations can be prolonged, such as renewable energy droughts.
- Outages associated with ageing coal plants are contributing to market instability as these plants exit the market.

- International gas price variability and its impact on the costs of operating gas-fired electricity generation.
- The growing adoption of behind-the-meter, weather-dependent and energy-limited resources.
- Increasing demand from electrification and the potential for renewable shortages to coincide with high system demand.
- The impact of extreme weather events straining the electricity system.

Without reform through the recommendations outlined in the previous chapters, the Panel is concerned that liquidity, price transparency and access to hedging contracts for retailers may decline.

6.2 Consumers should have access to multi-year fixed-price contracts and pricing information

The recommendations in the previous chapters should facilitate the trading of risk management products for longer periods into the future. The contracts co-design process (**Recommendation 7**), MMO (**Recommendation 6**) and ESEM (**Recommendation 10**) could extend price transparency for suitable products to manage risk in a firmed renewables system over decadal timeframes. With wholesale price transparency in place and a liquid derivatives market facilitating access to longer-dated risk management products, retailers should be well positioned to offer multi-year fixed-price contracts to electricity consumers. Multi-year fixed-price contracts would help to deliver more predictable and stable electricity bills for electricity consumers.

The Panel notes that consumers should not be *required* to enter multi-year fixed-price contracts. Rather, consumers should be given the *option* to take up multi-year offers subject to their own personal circumstances. This would also require changes to early exit fee restrictions within existing consumer protection frameworks.

6.3 Most consumers want simple price offers and predictable bills

Consumers have diverse preferences about how they manage their electricity consumption and behind-the-meter services that they wish to purchase from their retailer. This diversity is also influenced by new CER technologies and aggregation services that enable consumers to benefit from both self-consumption of electricity and exports to the grid. Stakeholders highlighted that electricity consumers are not homogenous:

> *Any conversation on activating consumer participation in energy markets must begin by recognising the immense variation in energy consumers. This is common to both households and commercial and industrial energy consumers. While there is a minority of 'prosumers' who are highly engaged and are willing and able to adjust their consumption to respond to spot prices, most energy users are more concerned with the services energy provides (a cool house, a hot meal, a productive factory, etc).* **– Energy Efficiency Council**[510]

The Panel has heard that most consumers want simple, reliable and affordable electricity services. The January 2025 Energy Consumers Australia (ECA) Energy Report Card 'Consumer knowledge of electricity pricing and responsiveness to price signals' indicates that, based on a survey approach,

[510] Energy Efficiency Council (2025), Submission to the initial NEM Review consultation.

54% of consumers prefer a basic relationship with the energy system, seeking a simple and reliable electricity service at a reasonable price. The Report Card also indicates that many solar rooftop owners are passive, with 46% of those consumers seeking only basic engagement.[511]

Relatedly, the Australian Competition and Consumer Commission's (ACCC) December 2024 Inquiry into the NEM indicates that consumer switching activity remains low at around 20% each year and that 81% of consumers could be on a better offer.[512] This suggests that many consumers are failing to switch even if there are better offers available.

Stakeholders have also indicated that most consumers want simple, actionable tariffs and predictable bills. For example, in its submission to this review, AGL stated:

> *AGL's view is that retail and network tariffs should be simple, actionable and fair:*
>
> - *Simple so that customers can understand and engage with the tariff*
> - *Actionable so that customers (or their agent) can respond effectively to capture the benefits*
> - *Fair so that the tariff is not punitive for a customer who can't respond.* **– AGL**[513]

Similarly, Energy Australia has indicated:

> *Our customers expect a secure, reliable and affordable electricity supply as the power system undergoes the transition to cleaner energy. It is also clear that customers want predictable prices and energy bills which do not result in continuous bill shock.* **– Energy Australia**[514]

By contrast, the ECA Report Card indicates that approximately 46% of consumers want a more active relationship with the market, including access to a choice of tariffs, being able to monitor and adjust their usage throughout the day to save money, and the choice to store or export electricity to the grid.[515] While these consumers may be more engaged, it is also important that tariff offerings are easy to understand:

> *The signals that end-consumers face need to be sufficiently simple so they can meaningfully respond and invest in CER, and this will involve both price- and non-price signals.*
> **– Australian Energy Market Commission (AEMC)**[516]

[511] ECA (2025), Consumer knowledge of electricity pricing and responsiveness to price signals – Consumer Energy Report Card January 2025, p 5.
[512] ACCC (2024), Inquiry into the National Electricity Market report, p 51, 54, 58.
[513] AGL (2025), Submission to the initial NEM Review consultation, p 11–12.
[514] EnergyAustralia (2025), Submission to the initial NEM Review consultation, p 2.
[515] ECA, op. cit., p 5.
[516] AEMC (2025), Submission to the initial NEM Review consultation, p 38.

6.4 Access to benchmark price information over multi-year horizons would benefit consumers

Stakeholders have indicated that many consumers would prefer stable and predictable electricity bills. If implemented, **Recommendation 6** and **Recommendation 10** would better facilitate longer-term risk management on behalf of consumers. By ensuring that risk management tools are suitable for a firmed renewables system and that derivative markets are liquid, accessible and transparent, consumers would be well placed to enter into contracts that facilitate long-term risk management on their behalf.

To maximise the benefits of these recommendations, electricity consumers would stand to gain from having access to longer-term or multi-year contracts that mitigate the impacts of wholesale market volatility. Under the framework outlined below, these multi-year contracts could be offered on a simple fixed-price basis through a retailer service (or subscription) fee specifying a simple price expressed in dollars. However, at present, customer contracting for retail services largely occurs through short-term retail contracts, with retail prices changing on an annual basis creating complexity and year-on-year variability for consumers.

The annual Default Market Offer (DMO) sets a maximum benchmark price that retailers can charge consumers on standing offer contracts. This price serves as a retail reference price against which retail market offers can be compared. However, consumers have limited information on future retail prices beyond the annual timeframe of the DMO. This lack of information hinders consumers' ability to assess whether a longer-term fixed-price contract extending beyond one year could be suitable for their personal circumstances.

Default Market Offer (DMO)

The DMO was introduced in 2019 and is the maximum price that retailers can charge electricity consumers on default contracts known as standing offer contracts. It is an electricity price 'safety net' protecting consumers from unjustifiably high prices, while also allowing retailers to recover costs.

The DMO price determination applies to residential and small business consumers in New South Wales, south-east Queensland and South Australia.

DMO prices for each region also act as a 'reference price' for residential and small business offers in that area. When advertising or promoting market offer pricing, retailers must show the price of their offer in comparison to the DMO/reference price. This assists consumers when comparing the price of different market offers.

The AER's role is to determine DMO prices annually.

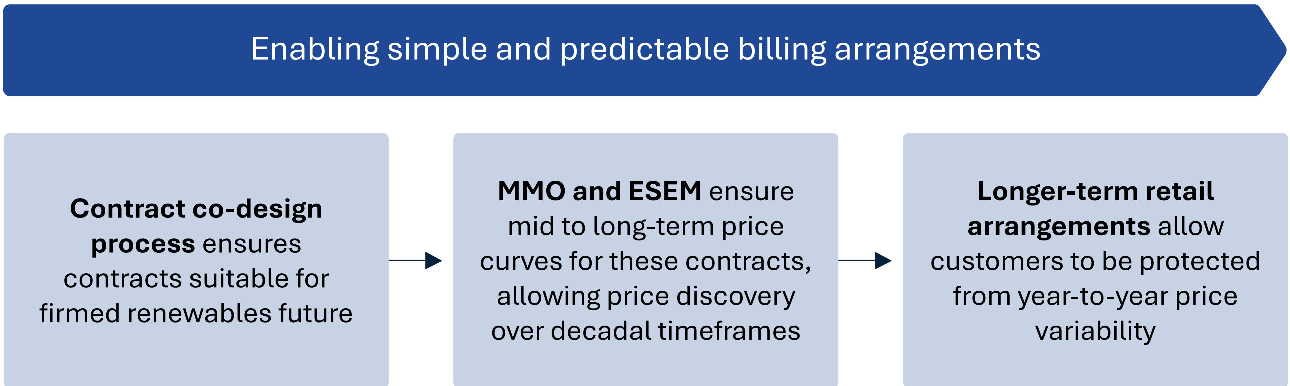
The Australian Government has recently completed a review of the DMO framework. In November 2025, the Department of Climate Change, Energy, the Environment and Water (DCCEEW) published an outcomes paper setting out a number of reforms to the DMO. These include revisions to the DMO objectives and methodologies, and the introduction of free power periods via a Solar Share Offer under the DMO framework.[517]

Regulated retail electricity prices apply in regional Queensland, the Australian Capital Territory and Tasmania.

[517] DCCEEW (2025), DMO Review Outcomes - 2025 Reforms to the Default Market Offer.

Throughout the Panel's consultation process, stakeholders have indicated that many consumers want simple and predictable billing arrangements. Without reforms that allow consumers to lock in wholesale prices over a longer period, consumers may be exposed to significant variability in their electricity bills caused by future wholesale market price volatility. To address this, the publication of transparent multi-year cost benchmarks may help electricity consumers contract for longer periods providing them with greater certainty over their future electricity bills. This would allow, but not compel, consumers to choose to enter into longer-term contracts.

Figure 64 – Enabling simple and predictable billing arrangements



Jurisdictions could consider establishing non-binding electricity cost benchmarks published for periods of up to five years (Figure 64). The benchmark wholesale costs could be developed by the AER utilising the trading data of the standardised contracts developed through the contracts co-design and MMO processes and published on the Energy Made Easy website. The published cost benchmarks would also incorporate forecasts of network costs in addition to the wholesale cost benchmarks. Retailers would then compete on the additional service fee charged to deliver the wholesale and network outcomes published by the AER.

Consumers would be able to view the cost benchmarks and service fees over both a short-term and multi-year horizon on the Energy Made Easy website. This would enable consumers to compare different retailer service fee offerings. For example, the cost benchmarks and service fees could be available on a monthly, quarterly and yearly basis, with annual prices published for one to five years ahead. These prices would help inform consumer decisions on whether a short-term variable or multi-year fixed-term electricity contract is more suitable for their circumstances.

Price discovery through multi-year retail price benchmarks would complement, rather than replace, the DMO. The DMO would remain as the annually updated cap on regulated standing offers and the reference price for market offers. Longer-term retail price benchmarks would help consumers assess multi-year contracts. Such a framework could be similar to how consumers in the banking sector access both long- and short-term interest rate information to decide whether to enter a fixed or variable interest rate home loan.

As illustrated below, consumer access to fixed interest rate loans in the financial services sector enables consumers to mitigate future interest rate variations and achieve more stable repayments they have budgeted for. In the case of electricity, consumers could also avoid significant electricity bill variability associated with wholesale market volatility by locking in a multi-year fixed-price deal with their retailer.

Fixed and variable rate home loans analogy

To better understand the advantages associated with longer-term electricity contracts, a comparison can be made to fixed and variable rate home loans.

Home loans

A fixed rate home loan maintains the same interest rate for the duration of the fixed term. A variable rate home loan interest rate fluctuates with a number of factors, including in part the official cash rate set by the Reserve Bank of Australia, as well as higher or lower funding costs for the lender.

The main advantage of a fixed interest rate loan is certainty; a customer can lock in or ‘fix’ their interest rate for a set period (typically one to five years). In contrast, the main advantage of a variable rate home loan is flexibility. Customers pay less on their home loan if interest rates fall. However, if interest rates rise, the customer’s lender may increase the cost of repayments.

Energy bills

Multi-year fixed-term energy contracts (e.g. three or five years) could provide additional choice for consumers that value certainty and predictability over flexibility. Consumers would weigh the pros and cons of both options, drawing on information from retailers and using the AER’s Energy Made Easy website.

There are international examples of price comparison sites that offer longer-term retail energy contracts. One example is the PA Power Switch Website in the US, which is the official website of the Pennsylvania Public Utility Commission. This website includes retail offers with varying terms including short term (three to six months) and longer term (12, 24 and 36 months).[518]

6.5 Retail cost benchmarks would promote competition between retailers

Benchmark costs could be published by the AER as a ‘cost stack’ including network, wholesale and government scheme cost components, supplemented by a simple service (or subscription) fee expressed in dollar or percentage terms set by each retailer.

In practice, benchmark wholesale costs for each NEM region would be informed by longer-term forward wholesale pricing achieved through the improvements to liquidity and price transparency delivered by the Panel’s wholesale market recommendations.

In terms of the network component, transmission and distribution network costs could be informed by network Tariff Structure Statements which are approved by the AER every five years and aligned with network reset periods. However, network expenditure forecasts would be needed for benchmark periods that cross over the five-year network revenue reset periods. Overall, the five-year regulatory reset period for networks, coupled with revenue smoothing across periods, could provide a basis for longer-term price transparency in networks costs, while also acknowledging that revenue adjustments occur between resets.

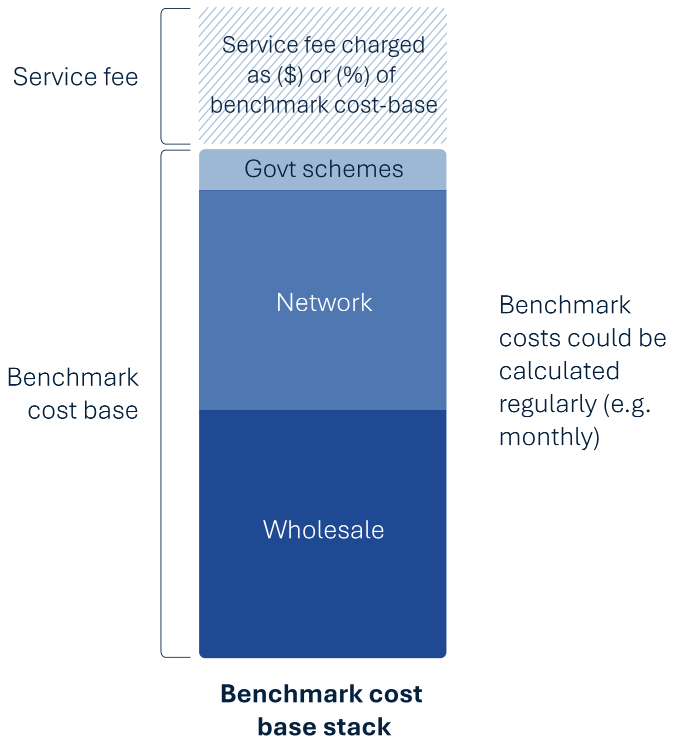
Retailers would have the flexibility to set their own service fees that could be published through the Energy Made Easy website. These fees would take the form of a simple price expressed in dollars or

[518] Pennsylvania Public Utility Commission (2025), PA Power Switch.

percentage terms, allowing consumers to compare different retailer service fees in choosing a retail offer. Service fees may vary across retailers as each will have different cost structures for delivering core retail services including risk management services and billing. Such an approach would ultimately help consumers identify those retailers who perform better in delivering their services as consumers are likely to choose a retailer with a lower service fee. This benchmarking approach could benefit consumers by simplifying choice between competing offers, thus fostering competition and promoting efficient provision of electricity services within the retail sector. This could apply in the jurisdictions with retail competition but would not be required in regions where electricity prices are regulated, such as regional Queensland, Tasmania and the Australian Capital Territory.

The benchmark and service fee approach is illustrated further in Figure 65.

Figure 65 – Benchmark and service fee approach (illustrative only)



6.6 Benchmark costs and service fees would be simple to understand for those seeking minimal engagement

The Panel is conscious that most consumers prefer simple, easy to understand and predictable electricity prices and bills – a simple price for a simple service.

The energy sector is already highly complex and can sometimes be difficult for consumers to navigate effectively. These complexities have prompted recent reforms, including the AER's Better Bill Guidelines,[519] which seek to simplify billing processes. The AEMC is also reviewing consumer pricing through its Electricity Pricing for a Consumer-Driven Future review.[520] The AEMC's review is examining the critical role that electricity pricing, products and services will play in meeting the diverse needs of

[519] AER (2023), Better Bill Guidelines
[520] See AEMC webpage, Electricity pricing for a consumer-driven future review

consumers, including enabling the use of CER that households and businesses are increasingly adopting as part of the energy transition.

The risks and challenges consumers face when navigating the market's complexities are also highlighted in Dr Ron Ben-David's proposal for the AEMC to consider an inner and outer market in his response to the AEMC's Pricing Review consultation paper.[521] The concept of a benchmark cost and retailer service fee, combined with an obligation for retailers to offer multi-year fixed-price contracts, aligns with the 'inner' or 'safe harbour' concept suggested by Dr Ben-David and provides consumers with a straightforward price offer.

An inner and outer market for electricity consumers

In his submissions to the AEMC's Electricity Pricing for a Consumer-Driven Future, Dr Ron Ben-David highlights that consumers possess varying levels of risk appetite and proficiency when it comes to participating in – particularly contracting within – the increasingly complex and risky electricity market. He urges the AEMC to adopt, as a key objective, the avoidance of exposing consumers to risks they are ill equipped to understand, manage or appropriately price.

In line with this objective, market and regulatory design should differentiate between an **'inner'** and **'outer'** consumer energy market:

- The inner market would act as a 'safe harbour', shielding consumers from risks and costs they are ill-equipped to understand, navigate or manage. Prices in this market would be governed by clear policy and regulatory principles.
- The outer market would be a space for consumers who choose to actively participate in the broader electricity market by trading their consumption, production and/or storage. These consumers would accept greater risks and benefits, with minimal regulatory oversight.

Dr Ben-David also calls for a statutory consumer duty in the outer market such that energy service providers should be required to make reasonable endeavours to act in the best interests of consumers when offering or delivering contractual services.

The Panel considers that there is significant merit in Dr Ben-David's proposed approach. As the energy transition progresses, price signals are expected to increasingly become volatile and variable, fundamentally reshaping how market participants manage and hedge short-term wholesale price risks. Derivatives markets must evolve to meet the diverse hedging needs of generators – from bulk energy to shaping and firming services – as well as the varying demand profiles and risk exposures faced by retailers and consumers. To sustain public support for the transition, consumers must have access to contracts that align with their individual risk appetite and proficiency in navigating market complexity.

The simple transparent benchmark cost model described above could form the basis of the inner market envisioned by Dr Ben-David.

Source: Dr Ron Ben-David, Monash Energy Institute, Submission to AEMC Pricing Review Consultation paper, December 2024.

Simple, transparent benchmark prices that include a retail service fee could provide a simple option for the segment of largely passive consumers that seek a basic electricity service. A simple benchmark

[521] R. Ben-David (2024), Submission to AEMC consultation paper: 'The pricing review – Electricity pricing for a consumer-driven future', Monash Energy Institute.

pricing framework also avoids exposure to the risks around more complex retail products and services, which some consumers may not be well placed to understand, manage or price.

However, benchmark offer arrangements may not be suited to those consumers wanting more active engagement with the market including consumers who wish to enter into price-responsive aggregation services or VPP arrangements – these involve more complex products and services, and control of CER devices. As such, these services are more likely to be suited to consumers with a higher risk appetite and proficiency in understanding the implications associated with third party control of devices. Consistent with Dr Ben-David's observations, these consumers could be subject to less prescriptive regulation and covered by the overarching statutory duty originally put forward by the AER. Such a duty would require that the energy service provider act in the best interests of the consumer. This is discussed further below in **Observation 4**.

6.7 There are many barriers to retailers offering longer-term contracts to electricity consumers, which in turn prevents consumers accessing the benefits of more stable pricing and predictable billing

Currently there are numerous restrictions on retailers applying early exit fees to consumers under the National Electricity Customer Framework (NECF).

Under clause 49A of the National Energy Retail Rules (NER), retailers can apply an early termination charge to a fixed-term retail contract provided that:

- the contract includes details of the amount or manner of calculation of the charge; and
- the charge is a reasonable estimate of the costs to the retailer resulting from the early termination – however, this cannot include costs based on "lost supply or lost profits".

Several NEM jurisdictions have also imposed similar restrictions on the ability of retailers to charge cost reflective and reasonable exit fees which may prevent the ability of retailers to impose such fees where a consumer seeks to enter a multi-year contract at a fixed price and then seeks to exit the contract before its expiration.

The Panel observes that the restriction in clause 49A prevents a retailer from recovering the costs based on lost supply or lost profit. In practical terms, this means a retailer cannot recover a proportion of the costs associated with any derivative contract for wholesale electricity services that it may have entered on behalf of that departing consumer, as part of its risk management role.

The restrictions may therefore prevent retailers from being able to recover the costs of entering long-term contracts for bulk energy, shaping and firming services under the Panel's proposed arrangements. This in turn creates an indirect barrier to retailers contracting to secure longer-term investment in bulk energy, shaping and firming to support the energy transition and to consumers being able to enter multi-year fixed-price contracts.

Energy ministers could consider reviewing these arrangements to enable more flexibility. The objective of this review would be to ensure consumers could (should they wish to) enter multi-year fixed-price contracts to protect themselves from future market volatility and variability in an increasingly weather-dependent system.

Relatedly, energy ministers could consider whether existing consumer protection arrangements are effectively supporting consumers in deciding whether to enter into a multi-year fixed-price arrangement with their retailer. This includes ensuring that consumers are provided with the correct information to understand the risks and trade-offs associated with entering into multi-year contracts and that contract outcomes align with a consumer's interests.

For those regions where electricity retail prices are regulated (namely, the Australian Capital Territory, Tasmania and regional Queensland), jurisdictional regulators may wish to consider whether a form of regulation (including a regulated exit fee) is required to enable the consumer to enter a multi-year fixed-price contract while ensuring that any exit fee is cost reflective and efficient.

Observation 2: Consider reforming network tariff structures to ensure they are more equitable and better aligned with wholesale market dynamics

The Panel has noted the very significant benefits that accrue from the deployment of CER. **Recommendation 2** is designed to ensure that the maximum benefit can be obtained from this deployment for all consumers. The Panel notes that in the long term, it will be important that economic signals from the wholesale market and network tariff design combine to maximise consumer benefits.

Continued use of volumetric network tariffs (including time-of-use volumetric tariffs) could result in some consumers avoiding contributing proportionately to network investment costs. This creates equity concerns, as consumers without CER, particularly those experiencing vulnerability, may bear a greater share of network costs. Such outcomes may intensify as the uptake of household battery storage grows.

To address this growing trend, the Panel observes that through its pricing review the AEMC could prioritise reforms that:

- Transition away from volumetric tariffs to other network tariffs with a higher fixed component based upon the individual consumer's actual use of network capacity at times of high electricity demand. This would help ensure a fairer allocation of network costs across all consumer types and support the availability of simple multi-year fixed-price retail offers as outlined in **Observation 1**, leveraging **Recommendation 6** and **Recommendation 10**.
- Require distribution businesses to offer dynamic (cost reflective) network tariffs for price-responsive and participative consumers (through their retailer), particularly those participating in CER aggregation. This would support more efficient market engagement for consumers capable and willing to respond to price signals. Furthermore, it could also lift capacity utilisation and potentially lower unit costs for all consumers.

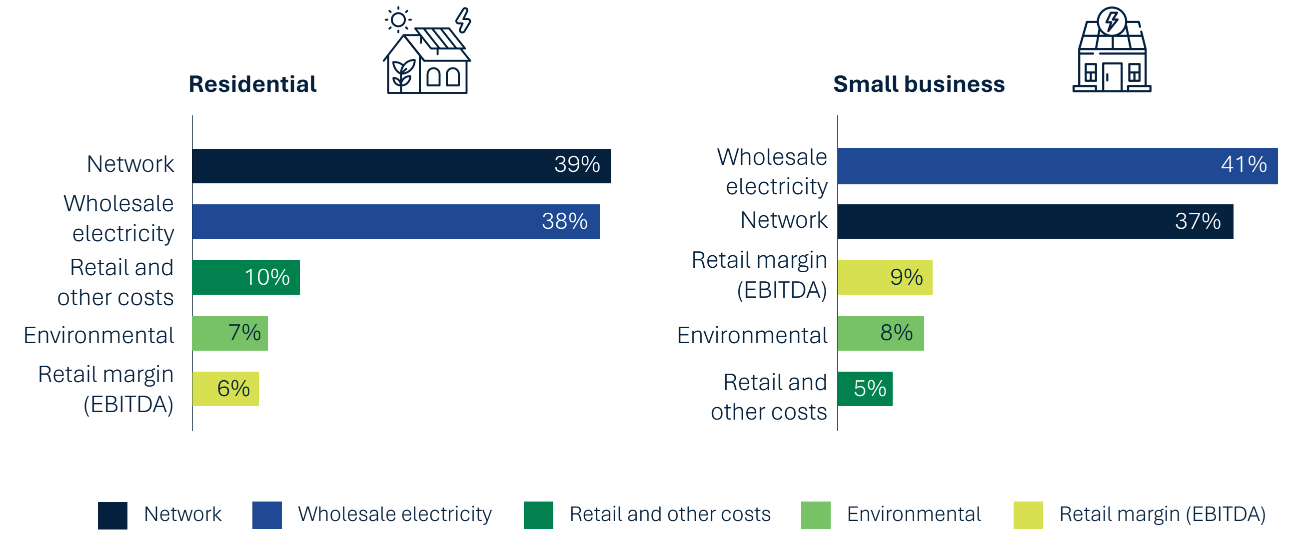
6.8 Network tariffs make up a large share of consumer bills

The cost of network services forms a key component of consumer bills. These include the costs of building and operating electricity networks and providing a return on capital deployed. Across the NEM, distribution costs are the largest component of network costs, followed by transmission costs.[522]

Figure 66 provides an estimated cost breakdown of residential and small business electricity bills for 2023–24, showing that network costs comprise close to 40% of the bill for residential and small business consumers.

[522] AER (2024), State of the Energy Market Report, p 244.

Figure 66 – Cost breakdown of residential and small business electricity bills for 2023–24



Source: AEMC (2025), Discussion Paper: The Pricing Review, p 17 based on ACCC analysis and graphic set out in the ACCC, Electricity Inquiry report of December 2024.

Network businesses are monopolies regulated by the AER via a network reset process that establishes revenue caps for each network across a five-year period. Under this process the AER also assesses and approves network pricing proposals from network businesses through Tariff Structure Statements, which also extend over a five-year period.

The AEMC has recently noted that 62% of consumers are on flat volumetric network tariffs with the same price applied per unit of energy consumption (kWh) of electricity across the day, while 21% are on time-of-use network tariffs (where the volumetric rate changes over the day) and the remaining 17% are on demand tariffs. Demand tariffs or charges are based on the maximum power used within a specified period.[523]

Network tariffs are designed to recover the costs of network infrastructure that has already been built, while also signalling to network users the costs associated with future investment. The Network Pricing Objective set out in clause 6.18.5(a) of the NER provides that the network tariff for a service should reflect the efficient costs of providing the service to a retailer. The NER also sets out the Network Pricing Principles, which include that each tariff must be based on the long-run marginal cost of providing the service to the retail consumers assigned to that tariff, and recover total efficient costs and expected revenue in a way that minimises distortions to price signals for efficient usage.[524]

6.9 Retailers mediate tariff signals, shaping how consumers respond to network costs

The setting of distribution network tariffs can have important impacts on how consumers use their electricity, including how the owners of CER assets optimise these assets either through self-consumption or through access to aggregation services such as VPPs. Put simply, it is the combination of wholesale market signals and network tariffs that drives participant behaviour.

[523] AEMC (2025), Discussion Paper: The Pricing Review, p 54–55.
[524] See NER clause 6.18.5 (e) to (j).

The extent to which network tariff structures are reflected in retail prices is determined by a consumer's retailer. A retailer may choose to pass through these signals directly to the consumer via their retail offer, but could also choose to adjust the signal or not pass it through.

In this sense both the setting of network tariffs and the extent to which they are reflected (in addition to wholesale costs) in retail prices for consumers will impact consumer behaviour and particularly the use of CER assets including solar photovoltaic (PV) and battery storage. In turn, these behaviours and the way in which CER is deployed can impact on the dynamics of the wholesale market. Network tariffs, wholesale prices and wholesale market participation opportunities come together in retail price and service offerings to shape consumers' overall demand (including their use of and investment in CER) over time.

As outlined in **Recommendation 2** in **Chapter 3: Ensuring effective operation of the spot market**, the Panel is recommending measures are taken to increase visibility of aggregated CER exports in the NEM, particularly as take up of household battery storage increases. The Panel also observes the structure of network tariffs can influence wholesale market outcomes and how greater efficiency could be achieved through increased alignment across networks and wholesale markets. These observations are set out further below.

6.10 Network tariffs have evolved towards greater time-of-use based differentiation

Australia's record uptake of household solar PV has resulted in very low grid demand in the middle of the day. However, households and businesses have much greater demands on the grid during morning and evening peak demand periods and overnight. Historical growth in evening peak demand has required networks to invest in expanding the capacity of the system. The costs of these investments are recovered through network charges.

The use of flat volumetric charges has obvious shortcomings given these market dynamics. Networks have responded by increasingly offering time-of-use tariffs including 'solar sponge' and export reward tariffs that encourage consumers to consume more electricity when overall demand on the system is low and consume less when overall demand on the system is high. Tariffs such as these can help smooth demand throughout the day, reducing the peaks which can drive investment costs.

The AER promotes collaboration between networks, retailers and consumers through trials of new and innovative network tariffs to develop ways to incentivise consumption when demand is low and disincentivise consumption when demand is high. An example of this type of trial is SA Power Networks residential 'electrify' trial with a targeted peak window and solar sponge designed to encourage consumers with flexible load and solar PV to shift electricity use to during the day or overnight.

Some distribution networks are also using demand tariffs to recover network costs. As noted above, these charges are based on the maximum power used by a consumer within a specified time period. The AER has recently issued a decision on the tariff structure statements for the Ergon and Energex distribution businesses in Queensland, which approved both its demand tariffs and time-of-use tariffs for household and small business customers but required these distributors to change the default network tariff assignment for those customers away from demand tariffs and onto time-of-use tariffs. In making these decisions the AER has indicated that retail customers may be unable to respond to or mitigate the impact of demand tariffs because they do not understand them.

The AER has referred to the ACCC Electricity Inquiry Report (December 2024) findings that approximately 51% of customers with demand retail offers were paying prices at or above the DMO, compared to 38% of customers on the flat rate and 27% on time-of-use tariffs.[525]

The AEMC's pricing review is considering network and retail tariffs, how these interact and how they can operate together to facilitate the design and offering of electricity products and services for consumers through the energy transition, including through enabling CER. The AEMC is due to deliver a final report on the review in early 2026.

6.11 Network tariffs should drive efficient utilisation of network capacity

The Panel notes that there are significant interlinkages between wholesale prices and network tariffs and retail pricing. Network tariffs and retail pricing can play a key role in determining price signals for end consumers.

Overall, the Panel notes broad agreement amongst stakeholders that the combination of wholesale market settings and network tariffs should drive efficient utilisation of electricity infrastructure.

Network tariffs should provide effective signals to retailers (and ultimately consumers) that can help drive network efficiency. Specifically, if designed correctly these tariffs and the way they are reflected in retail offers can shape consumer behaviour in a way that can reduce or avoid inefficient future network investment, the costs of which are borne by consumers. The ability of network tariffs to shape consumer behaviour is also critically dependent on the characteristics of the consumers who are facing these price signals including their ability and willingness to modify their electricity consumption patterns.

In addition, stakeholders have noted that network tariffs should encourage a fair and equitable sharing of the costs of the network among electricity consumers including both those who own and do not own CER assets.[526]

The Panel notes the recent position of the AEMC as set out in its March 2025 updated guide on decision making under the National Energy Objectives that achieving equitable outcomes "is essential for building and maintaining the social licence that is necessary to enable a timely and least cost transition".[527]

6.12 Today's network tariffs may conflict with wholesale market signals

While progress has been made on network tariff reform, the Panel notes that the generalised signals provided by volumetric long-run marginal cost-based time-of-use network tariffs (for example, with network-wide peak time periods) may be misaligned with the costs of building the network to meet peak demand. In particular, as greater uptake of behind-the-meter batteries occurs, many households will have a much lower overall consumption (including during many peak periods) but may still use the grid almost entirely on the largest peak demand days.

The combination of responsive CER technologies and aggregation services effectively enables these resources and services to inject/withdraw electricity into/from the grid in very short response times, and the Panel is concerned that generalised and broad long-run marginal cost volumetric tariffs

[525] AER (2025), Final Decision Attachment 19 - Tariff structure statement - Ergon Energy and Energex - 2025-30 Distribution determination revenue proposal - April 2025, p 17–18.
[526] The AEMC makes similar observations regarding network tariffs and equity in their 'Pricing Review Discussion paper', p 54.
[527] AEMC (2025), How the National Energy Objectives shape our decisions, p 10.

may ultimately impede the integration of these resources into the NEM, at a cost to consumers. For example, a time-of-use tariff with a broad peak period could capture times of low wholesale prices without reflecting actual network constraints. A high network tariff that is passed on to a customer could constrain a household's ability to charge a battery or to consume electricity when this may otherwise help to increase demand on the electricity system at a time of negative wholesale prices.

An example of the problems associated with misaligned network tariffs is set out in the AEMC's 2025 pricing review paper:

> *Current network tariffs can conflict with the wholesale market signal. Where the network signal is accurate and effective, this is not necessarily problematic and consumers who choose to engage can respond to the more valuable signal. Consumers may currently, however, be receiving network signals that get in the way of the wholesale market engagement without necessarily reducing network costs.* **– AEMC**[528]

The Panel considers that the cost drivers of wholesale pricing and distribution networks are generally likely to align. Specifically, the Panel expects that at times of the day when electricity demand is high compared to available supply (reflected in higher wholesale prices), distribution networks are also likely to be constrained due to limited import capacity. This also means that the need for network augmentation is likely to align with periods of wholesale energy market scarcity and higher wholesale prices, which are more likely to occur during evening peak demand.

This does not mean that network tariffs signals must 'give way' to wholesale price signals. Where there are genuine local constraints on the distribution network (both import and export constraints) that restrict retailers and consumers from accessing the wholesale market, these could be signalled through dynamic network tariffs[529] and dynamic operating envelopes. The Panel notes that several stakeholders commented that dynamic network signals that are more responsive to real-time changes in the wholesale market can deliver important benefits by better enabling CER participation through aggregation services.[530] In this context, Ausgrid is currently undertaking a trial, Project Edith, which involves the application of dynamic near-real-time price signals in relation to VPPs and their customers.[531]

6.13 Network tariffs may be preventing efficient utilisation of the network and creating inequitable outcomes for consumers

Recent AER analysis in its September 2024 Electricity and Gas Networks Performance Report, suggests that the capacity of the distribution networks is under-utilised (see Figure 67).

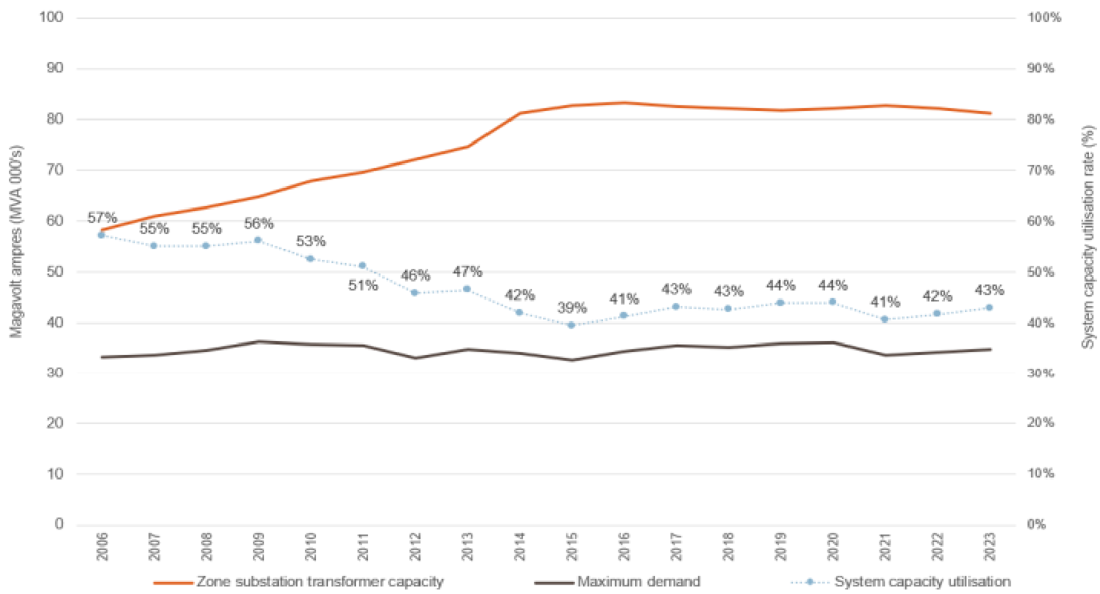
The Panel observes that network prices that do not reflect under-utilisation of network capacity at a distribution level may be impeding efficient wholesale electricity market outcomes for consumers. The AER has indicated that:

[528] AEMC (2025), Discussion Paper: The Pricing Review, p 59.
[529] A dynamic network tariff provides for network prices to change across five-minute periods (aligned with the NEM wholesale market) reflecting network conditions at these times in specific locations. These tariffs are currently being explored through Ausgrid's Project Edith trial.
[530] Submissions to the NEM Review initial consultation from Origin (p 28), Reposit Power (p 6) and Ausgrid (p 6).
[531] Submission to the AEMC Consultation Paper on Improving the NEM Access Standards (Package 2) Ausgrid (p 6).

> *Low utilisation (i.e., high spare capacity) means a network can service large increases in peak demand. However, low utilisation may also mean customers are paying for network assets they rarely use, questioning whether the capex investment was an efficient cost… Zone substation transformer capacity, maximum demand and utilisation have all been relatively flat since 2015, which coincides with a steep decrease in augmentation expenditure.* **– AER**[532]

Localised constraints from PV system exports are becoming more prevalent as more consumers install solar PV systems, requiring distribution network service providers to possibly limit CER exports into the grid to protect network assets.[533] The rapid installation of residential batteries expected as a result of policy interventions is likely to at least partially address this issue.

Figure 67 – Network utilisation by DNSPs



Source: AER (2024), Electricity and Gas Networks Performance report, September 2024, p 42.

Drawing upon AER and AEMC analysis and stakeholder feedback, the Panel notes that existing network tariff signals are blunt and not aligned with wholesale pricing signals to deliver least cost electricity outcomes for consumers. In particular, existing long-run marginal cost approaches to developing demand tariffs and time varying volumetric tariffs may not be sufficiently targeted or granular and may instead be disincentivising usage of electricity at times when network capacity is not congested or constrained. The Panel recognises that this depends on whether tariffs such as these are presented to consumers with options to adjust behaviour by their retailer (e.g. CER deployment).

Broadly the Panel notes three issues raised by stakeholders through the review in relation to volumetric long-run marginal cost tariffs:

1. **Volumetric time varying tariffs based on long-run marginal cost may constrain the use of spare distribution network capacity at times when either more supply or consumption is needed in the wholesale market.** Without reform, this could exacerbate wholesale market

[532] Electricity and gas networks performance report, AER (September 2024), p 41 and 42.
[533] Ibid.

volatility in an increasingly weather-based energy system. These effects are dependent on the extent to which these tariffs are reflected in retail contracts and technology options that are provided to the customer (e.g. solar PV, battery energy storage systems).

2. **Volumetric time varying tariffs based on long-run marginal cost are sending generalised and broad network investment signals to retailers and consumers that may not relate to those parts of the network where investment is required either now or in the future.** In practical terms, this means that network pricing signals are being used to modify behaviour when it is not necessary to do so as the network, or that part of the network, is unconstrained. The use of CER accompanied by dynamic network tariffs and dynamic operating envelopes is seen as a key means of overcoming this.
3. **Volumetric tariffs enable self-consuming owners of CER to avoid paying for the use of the grid, while other non-CER owning consumers pay for the network.** Stakeholders have expressed concern that these effects will become greater as household battery storage ownership increases. Without reform of network tariff methodologies, the existing arrangements are likely to have significant fairness and equity implications. As noted in **Chapter 2: Trends and challenges in the NEM**, increased weather dependency is likely to result in greater volatility and variability. In times of system stress, CER availability may be limited (due to exhaustion of behind-the-meter energy and storage resources) and households are likely to use the grid for most of their consumption for at least some days each year. If tariffs are levied through volumetric use of energy, the costs associated with the capacity used by the household when demand is highest (which reflects the actual cost of building the network) will be paid for by non-CER households. The Panel notes that similar concerns have been raised in the AEMC's Discussion paper on the Pricing Review. The AEMC has indicated that "current network tariffs allow consumers, particularly those with CER to pay less for network services without necessarily contributing to reducing future network costs. This shifts costs onto other consumers, including the most vulnerable".[534]

The above issues relating to network tariff implications for investment in and operation of consumer energy resources are in addition to those for medium-scale distributed energy resources discussed under **Recommendation 11G**. Ideally, these issues would be considered concurrently so that network tariffs (as a whole across transmission and distribution) are encouraging efficient investment and operating decisions for large- and small-scale resources. This is a precondition for fully realising the Panel's intended level playing field for different resources in the ESEM.

6.14 Retailers are responsible for managing network tariffs on behalf of consumers

A core function of retailers is providing consumers with products and services that allow them to best respond to wholesale and network tariffs. In some cases, retailers may choose to pass on time-varying tariffs. In other cases retailers may choose to translate network tariffs into simple retail offers while managing the network tariffs themselves. Ultimately, it is the Panel's view that retailers should be responding to network tariffs by providing products and services to end use consumers that allow them to more efficiently use the network.

The Panel notes the AEMC's recent final determination on the Accelerating Smart Meter Deployment rule change which introduced consumer safeguards around the pass-through of cost reflective

[534] AEMC (2025), Discussion Paper: The Pricing Review, p 55.

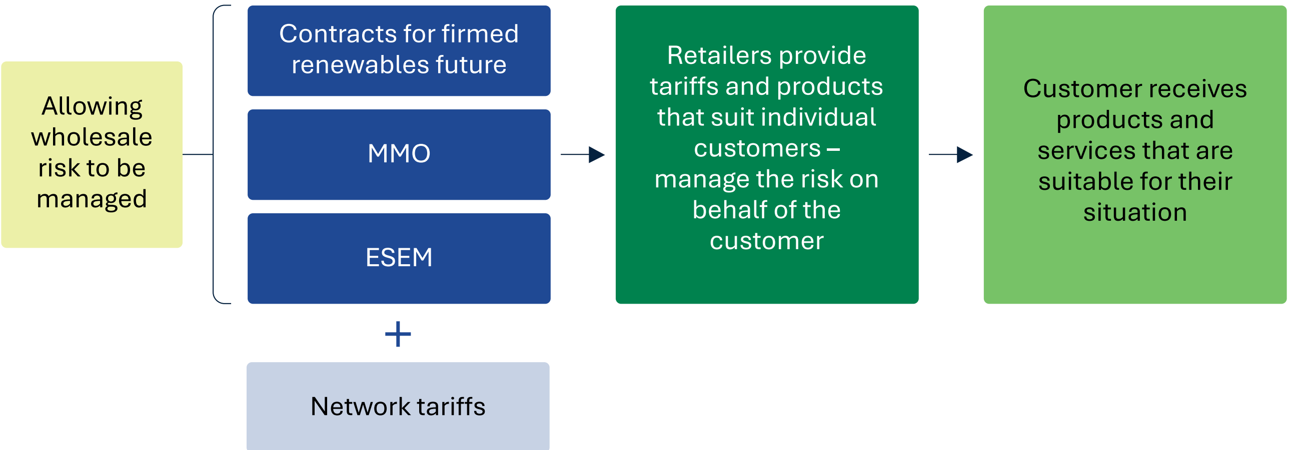
network tariffs upon deployment of a smart meter.[535] These include a requirement (applicable for two years) on retailers to obtain a consumer's consent before varying their retail prices (i.e. placing the customer on a cost-reflective tariff) following the installation of a smart meter. The rule also introduced a requirement that designated retailers must make flat tariff standing offers to consumers with a smart meter, subject to implementation by jurisdictions.

In its final determination the AEMC noted that retailers could take a portfolio approach in managing these reforms, choosing how to spread any costs across their customer base. The AEMC also stated it did "not consider that retailers will be uniformly worse off facing a network tariff that they cannot directly pass on to consumers. While we acknowledge that retailer costs may increase for some customers, cost-reflective network tariffs will result in lower costs for other customers".[536]

The AEMC's determination affirms that retailers have a role in managing network tariffs on behalf of consumers, and that the application of cost reflective tariffs should not mean that they need to be automatically passed through.

This is particularly important given that (as noted above) many consumers seek a simple retail offer and may not have the capacity, interest or capability to navigate more complex tariffs. Put simply, the Panel views retailers as the customer's agent managing the risks associated with both wholesale markets and network tariffs. By providing innovative and new product offerings (e.g. in-home/business energy management, solar PV, batteries, electric vehicles etc), retailers should be providing customers with options to minimise their energy bills.

Figure 68 – Panel Recommendations should assist retailers in managing risk for customers



[535] AEMC (2024), National Electricity Amendment (Accelerating Smart Meter Deployment) Rule, p 32.
[536] Ibid.

6.15 Simpler network tariffs for consumers and targeting network congestion

Approaches to tariff methodologies and the application of these methodologies are matters for both the AEMC in determining pricing objectives and principles and the AER through its decisions on proposed tariff structure statements. The observations on future network tariff reform set out in this chapter, and the views received from stakeholders, could form an input into the AEMC's pricing review.

The Panel considers that there is merit in the AEMC considering:

- Moving towards more fixed-price structures for network tariffs based upon users' actual use of the network (as measured by their highest use of the network's capacity at times of high electricity demand). This could be translated into simple retail offers for the majority of electricity consumers that seek a simple price for a simple service. The Panel notes that in considering any move towards fixed rate tariffs it is important that the equity and distributional impacts are considered by policy makers.
- Simple retail offers could also be accessed by those CER owners that self-consume and who do not want to purchase aggregation-based services from retailers.
- By contrast, consumers that purchase aggregation services (and for whom there is a greater understanding of and appetite for risk) could be assigned more dynamic and responsive network tariffs; for example, to reflect the forward-looking cost of investment to address local congestion in their network area.

Overall, where there are limited or highly localised constraints on distribution networks, it is arguable that these should be priced through dynamic and/or critical peak pricing mechanisms. Residual network costs that are unrelated to future network requirements could be recovered through a fixed charge rather than generalised time-of-use volumetric charges.

As noted above, further analysis would be required in relation to these high-level observations to determine appropriate network tariff methodologies for the medium and long term.

Observation 3: Consider updating the methodology for regulated retail price benchmarks (such as the DMO) to reflect the evolving nature of the derivatives market in the context of new contract structures and the MMO

The current methodologies used to calculate the wholesale cost component of the DMO influence retailer hedging strategies. The AER relies on a book-build approach to determine hedging costs. The DMO approach is based on contracts purchased two to three years in advance. The Panel's recommendations in relation to an MMO and derivative contract structures (**Recommendation 6**) provide an opportunity to ensure that retail pricing methodologies are based on the most efficient hedging strategies.

The Panel observes that the AER could consider revisiting the DMO book-build methodology to incorporate the new and longer-dated hedging instruments delivered through the contract co-design process. Given the Panel's finding that the DMO methodology is a material driver of market retailer hedging strategies, adjusting the methodologies to reflect long- and medium-term price signals would assist retailers in offering stable, longer-term pricing for consumers.

The Panel's recommendation for the AER and the ESEM Administrator to work with industry to ensure that contracts available to trade for the purpose of market making allow for the DMO methodology and any new retail benchmarking to evolve to suit the needs of an increasingly weather-dependent market (**Recommendation 6**).

The Panel's recommendation to establish a market making obligation is aimed at creating transparent price signals and lengthening the period over which derivative markets operate. The obligation would be built around a standardised and fungible set of tradeable contracts that meet retailers' and generators' changing risk management needs in a more weather-dependent environment. These contracts would be determined by an industry-led process convened concurrently with the AEMC Reliability Panel's Review of the market price settings (**Recommendation 7**).

Given the DMO's influence on retailer hedging strategies, the AER would need to refresh wholesale electricity cost methodologies to factor in these new contacts suitable for a firmed renewables electricity system. This would help promote uptake and liquidity and ensure that retailers and their customers capture the full benefits of these reforms, if adopted.

Observation 4: Consider extending the National Energy Customer Framework to cover new energy services, including CER aggregation, and explore the introduction of an overarching consumer duty to protect customers engaging with more complex service offerings

The uptake of new energy services, including aggregation services, has the potential to deliver meaningful benefits to both individual consumers and the broader energy system. However, these new services are inherently complex and introduce new risks that may affect consumers' access to electricity as an essential service. Currently, such services fall outside the scope of the existing energy consumer protection framework, exposing consumers to potential harm. Without appropriate consumer protections, poor outcomes could erode trust, reduce engagement and ultimately hinder the widespread adoption of these innovations, to the detriment of all consumers.

The Panel observes that jurisdictions could prioritise work through the National Consumer Energy Resources Roadmap to address this regulatory gap by extending the National Energy Customer Framework to cover new energy services. This work should include consideration of an overarching consumer duty, requiring retailers and service providers to act in the best interests of consumers when offering or delivering new energy services.

6.16 Current protections do not adequately cover CER aggregation services

In **Chapter 3: Ensuring effective operation of the spot market**, the Panel has made recommendations that would increase visibility of CER. Given the broader benefits of participation in the wholesale market, the Panel notes that many stakeholders expect significant growth in the uptake of CER aggregation services. CER aggregation services currently sit outside the existing energy consumer protection frameworks, namely the NECF. Instead, these services are covered solely by the Australian Consumer Law (ACL).

Many new energy services including aggregation and VPP products are complex and are becoming increasingly intertwined with the provision of electricity as an essential service. New energy and aggregation services involve customers handing some control over their CER assets to a third-party aggregator for optimisation within a broader portfolio. In some circumstances this can lead to customer detriment if risks are not adequately explained upfront or where a customer contracts for a service that is not suited to their personal circumstances and which impacts negatively on the provision of electricity as an essential service. For example, a poorly designed and implemented retail product to control air conditioning assets may reduce the customer's ability to heat or cool their house at certain times of the day.

6.17 The AER has identified consumer harm risks in aggregation services

In 2022 the AER completed a review of the consumer protection arrangements governing new energy services and noted risks of harm to consumers in relation to contracts, information provision, performance of services, control of assets, payment difficulty, dispute resolution and service provider conduct.[537] The AER concluded that the NECF's energy-specific consumer protections should be updated to include new energy services including aggregation services. Effective energy-specific consumer protections that extend beyond the ACL would support consumer trust and confidence. This would in turn encourage the wider take-up and effective use of new technologies and changes in consumer behaviour, driving further innovation and realising the significant benefits that new energy services bring to the energy transition.

The AER also put forward the concept of establishing an overarching consumer duty that would apply to sellers of new energy services and which would require the seller to act in the best interests of the consumer. The introduction of an overarching consumer duty would ensure a focus on achieving favourable consumer outcomes, recognising the growing role that consumers are playing in the energy market. Support for the reform of energy consumer protection arrangements, including an overarching duty, has also recently been provided by ECA through its report on opportunities for CER participation in wholesale markets and grid services. This report notes:

> *Fit-for-purpose consumer engagement and protections will improve social licence through a more engaged customer base ... Consumer protection frameworks should evolve with the flexibility to account for the range of energy services available to consumers.* **– ECA**[538]

6.18 The Panel supports prioritising consumer protection reform to build trust and CER uptake

Governments are currently considering consumer protection reform for new energy services, including an overarching consumer duty, as part of the CER Roadmap.[539]

In March 2025 energy ministers initiated the Better Energy Customer Experience workstream to review energy consumer protection frameworks.[540] This work is being led by DCCEEW in conjunction with state and territory government officials and will build upon the work undertaken by the AER.

The workstream will aim to identify existing, emerging and potential future challenges in consumer protection settings and to assess whether the NECF remains fit for purpose.

The work will develop reforms where required to ensure a smooth energy transition that supports consumers and the realisation of the benefits of the transition. The Panel considers that reforms to the NECF are needed to incorporate new energy services and should be prioritised by governments. The current arrangements may lead to poor consumer outcomes that lower trust and which therefore undermine take-up of new energy services.

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537 AER (2022), Review of consumer protections for future energy services.
538 ECA and Rennie Advisory (2025), Opportunities for CER participation in wholesale markets and grid services, Final Summary Report, p 10.
539 Work on consumer protections reform is being undertaken under initiative C.1 of the CER Roadmap ('National Consumer Energy Resources Roadmap', Energy and Climate Change Ministerial Council, 2024, p 14).
540 Better Energy Customer Experiences - Department of Climate Change, Energy, Environment and Water

Stakeholder feedback in response to the Draft Report

The feedback provided in response to the Draft Report recognised that the Panel had made observations, rather than recommendations, in this section of the report.

In this context, only a limited number of stakeholders provided feedback on the Panel's consumer-focused observations. This response is consistent with the Panel's intent, as these were presented as observations rather than formal recommendations, acknowledging that network and retail market reforms fall outside the scope of the NEM Review. Nevertheless, the Panel considers the pursuit of improved consumer outcomes to be a foundational principle of its reform package.

Stakeholders who did provide feedback broadly supported further work on empowering consumers through simple, multi-year retail contracts. However, concerns remain around implementation complexity, equity impacts of fixed rate network tariffs, and the potential for retail risk premiums. There was strong consensus on the need to extend consumer protections to new energy services, with many advocating for a proportionate, principles-based framework.

Observation 1: Consider the development of simple, multi-year fixed-price retail contracts

A small number of stakeholders responded to the Panel's proposal of long-term fixed-price contracts, expressing mixed views. Stakeholders generally supported further work to be done on this topic, recognising the need for further analysis, such as a cost benefit assessment.[541] Some favoured the contracts as an opt-in basis to provide consumers with greater price stability, predictability and greater control over their energy bills.[542] Energy Australia noted that these products could empower households, particularly if supported by improved price transparency and benchmark cost information.[543]

However, views diverged on feasibility and risk. The AER questioned the long-term benefits, citing limited wholesale price transparency and the potential for risk premiums that could leave consumers locked into unfavourable plans. Some retailers highlighted implementation challenges and cautioned against creating network tariffs for selected customer types or technologies.[544] Others noted the need for strong consumer protections to ensure consumer choice, equity and to prevent adverse outcomes.[545]

Observation 2: Consider reforming network tariff structures to ensure they are more equitable and better aligned with wholesale market dynamics

Stakeholder views on network tariff structure reform were mixed. Some stakeholders supported the principle of greater cost reflectivity, which could support more equitable outcomes for consumers.[546] ECA supported the proposal to reform distribution network tariffs by shifting to a greater fixed charge proportion noting it has provided detailed analysis on this to the AEMC's Pricing Review.[547]

541 Submissions to the NEM Review Draft Report consultation include AER (p 8) and IEEFA (p 13).
542 Op. cit. EDF Power Solutions (p 6), Energy Australia (p 3), Centre for Policy Development (p 5) and IEEFA (p 13).
543 Energy Australia (2025), Submission to the NEM Review Draft Report consultation, p 3.
544 ActewAGL (2025), Submission to the NEM Review Draft Report consultation, p 3.
545 AGL (2025), Submission to the NEM Review Draft Report consultation, p 14.
546 Submissions to the NEM Review Draft Report consultation include Energy Networks Australia (p 9), Essential Energy (p 3), SACOSS (p 1) and SA Power Networks (p 1).
547 ECA (2025), Submission to the NEM Review Draft Report consultation, Finncorn Consulting report, p 5.

The AER noted that going forward, it will be critical that there are signals for reducing future network costs through incentivising shifting of consumption and generation. It emphasised that any rebalancing of tariffs must ensure cost recovery remains both efficient and equitable.[548] Essential Energy and SA Power Networks supported the principle of equitable cost recovery but noted that in low-density areas, fixed charges are already relatively high due to the smaller customer base. Energy Networks Australia (ENA) noted that recovering a greater, more cost reflective share of residual costs through fixed access charges would improve equity between CER and non-CER owning consumers and reduce variability in network costs for retailers. There was broad support for maintaining consumer choice, with stakeholders favouring simple default tariffs (e.g. time-of-use) alongside opt-in access to more complex tariffs for sophisticated or price-responsive customers.[549] In relation to wholesale market and network pricing interactions Ausnet agreed that broad network tariff settings can sometimes conflict with wholesale pricing.[550] Similarly, the EV Council supported aligning network time-of-use tariff windows with wholesale market pricing.[551]

However, other stakeholders disagreed with the need for reforms at this time.[552] Some preferred further consideration, such as through the AEMC's Pricing Review or continuation of incremental change.[553] Others noted that a move towards greater fixed charge network tariffs could result in inequitable and regressive outcomes for impacted customers.[554] The Institute for Energy Economics and Financial Analysis (IEEFA) recommended the Productivity Commission undertake a first-principles review of the economic regulation of distribution networks, noting the role of aggregated CER as a substitute for network investment.[555] Others raised concerns that increasing fixed charges could undermine system efficiency and reduce incentives for demand-side participation.[556]

Observation 3: Consider updating the methodology for regulated retail price benchmarks (such as the DMO) to reflect the evolving nature of the derivatives market in the context of new contract structures and the MMO

A small number of stakeholders responded to the Panel's proposal that default pricing methodologies should evolve to reflect changing market conditions. All agreed that default pricing methodologies must remain fit-for-purpose as the market evolves.[557] Several submissions linked this principle to the operation of the DMO and Victorian Default Offer (VDO), noting that benchmark methodologies should reflect changing wholesale dynamics and hedging structures. Some supported updates to the DMO/VDO to better account for the cost of firming variable renewable energy and the use of longer-term contracts. They emphasised the importance of aligning default price benchmarks with realistic hedging costs to sharpen investment signals and reduce the risk of retailer under-contracting or exits.[558] The AER

548 AER (2025), Submission to the NEM Review Draft Report consultation, p 9.
549 Submissions to the NEM Review Draft Report consultation include ActewAGL (p 3), Origin (p 21) and SA Power Networks (p 5).
550 Ausnet (2025), Submission to the NEM Review Draft Report consultation, p 3.
551 EV Council (2025), Submission to the NEM Review Draft Report consultation, p 3.
552 Submissions to the NEM Review Draft Report consultation include Ausgrid (p 1) and Solar Citizens (p 17).
553 Op. cit. Ausnet (p 2) and Centre for Policy Development (p 5).
554 Submissions to the NEM Review Draft Report consultation, IEEFA (p 14–15) and Solar Citizens (p 16).
555 IEEFA (2025), Submission to the NEM Review Draft Report consultation, p 16.
556 Submissions to the NEM Review Draft Report consultation recommending consideration through the AEMC pricing review from ENA (p 9) and SAPN (p 1). See also submissions to the NEM Review Draft Report consultation from AGL (p 14), IEEFA (p 15), Solar Citizens (p 16) and AER (p 8–9).
557 Submissions to the NEM Review Draft Report consultation include EDF Power Solutions (p 6), AGL (p 14) and Origin (p 21).
558 EDF Power Solutions (2025), Submission to the NEM Review Draft Report consultation, p 6.

confirmed that it will continue to update its methodology to reflect new derivative products and market realities, consistent with its current practice.[559]

Observation 4: Consider extending the National Energy Customer Framework to cover new energy services, including CER aggregation, and explore the introduction of an overarching consumer duty to protect customers engaging with more complex service offerings

There was strong support for extending the NECF, or equivalent protections, to new energy services such as VPPs, distributed energy resources aggregators and flexible demand programs.[560] Stakeholders agreed that a fit-for-purpose framework is needed to protect consumers as the market evolves.[561]

Several stakeholders supported introducing an overarching consumer duty to build confidence and enable greater participation in demand-side markets. EDF Power Solutions supported extending the NECF with a proportionate consumer duty, while Essential Energy emphasised alignment with existing ACL provisions. Solar Citizens instead called for a purpose-built energy code to be established under the ACL.[562] SA Power Networks called for formal compliance and conformance obligations on CER aggregators. AGL advocated for a principles-based, nationally consistent and technology-neutral approach that preserves incentives for innovation. The AER similarly highlighted the need for fairness and transparency through the transition. Some stakeholders proposed going further, recommending the development of a new, technology-neutral energy code under the ACL and greater transparency in how VPP revenues are shared with consumers.[563]

Essential Energy noted that consumer protection issues are being addressed by the National CER Roadmap, including its consultation on technical priorities T1 and T2 (nationally consistent technical standards).[564]

[559] AER (2025), Submission to the NEM Review Draft Report consultation, p 9.
[560] Submissions to the NEM Review Draft Report consultation include AER (p 9), AGL (p 14), EDF Power Solutions (p 6), Essential Energy (p 4) and SA Power Networks (p 8).
[561] AER (2025), Submission to the NEM Review Draft Report consultation, p 9.
[562] Solar Citizens (2025), Submission to the NEM Review Draft Report consultation, p 17.
[563] Submissions to the NEM Review Draft Report consultation recommending a new energy code from Solar Citizens (p 17) and recommendation for more transparency in VPPs from IEEFA (p 16).
[564] Essential Energy (2025), Submission to the NEM Review Draft Report consultation, p 4.

Appendix A – Terms of reference

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TERMS OF REFERENCE

Review of Market Settings in the National Electricity Market to Follow the Capacity Investment Scheme

1. This terms of reference sets out an expert panel-led review supported by the Commonwealth Department of Climate Change, Energy, Environment and Water (DCCEEW), into market settings to promote investment in firmed, renewable generation and storage capacity in the National Electricity Market (NEM) following the conclusion of Capacity Investment Scheme (CIS) tenders in 2027.

2. The expert panel will consist of a full time Chair and three part time panel members with a diversity and depth of expertise, supported by robust governance arrangements to deliver independent policy recommendations that are in the long-term interests of energy consumers and Australia.

Background

3. The NEM, under the National Electricity Objective (NEO), was created to deliver reliable, competitively priced, safe and secure electricity services in the long-term interests of consumers. As a power system and wholesale market, it was designed to centralise and efficiently dispatch existing generation and to incentivise new infrastructure through its spot, contract, and retail markets in order to provide electricity at least cost to consumers.

4. It is essential that wholesale market settings in the NEM support Australia's clean energy transition by providing effective signals to incentivise investment in the optimal mix of energy resources to meet future electricity demand. These energy resources include firmed renewable generation, storage, bulk variable renewable energy (VRE) and Consumer Energy Resources (CER), which are forecast by AEMO to compose upwards of 60 GW of dispatchable capacity in 2050.

5. The Commonwealth Government responded to the need for an acceleration of investment in firmed renewable energy to replace ageing thermal coal generation capacity by introducing the CIS. The CIS will support an additional 32GW of firmed renewable energy generation and storage, underpinning around $74 billion in new investment nation-wide.

6. The CIS was supported by states and territory Energy Ministers through the Energy and Climate Change Ministerial Council (ECMC) as the preferred instrument in the near term for supporting additional investment in clean, dispatchable generation and storage capacity. CIS tenders will be conducted until 2027 for projects that are generating electricity on-grid by 2030.

7. Beyond this, there is a need for wholesale market settings to provide effective signals to investors for the provision of the optimal mix of energy in the NEM, ensuring resource adequacy and supporting reliability in the NEM at lowest cost to consumers.

8. To address this, at the November 2023 ECMC meeting, Commonwealth, state and territory Energy Ministers agreed that the Commonwealth would commence work with NEM

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jurisdictions on a review of market settings to promote investment in firmed, renewable generation and storage capacity in the NEM following the conclusion of CIS tenders in 2027.

9. The review will produce recommendations for consideration by Energy Ministers through ECMC.

Scope of the inquiry

10. The expert panel will recommend future market settings to promote investment in firmed, renewable generation and storage capacity in the NEM following the conclusion of CIS tenders in 2027. The expert panel will make actionable recommendations to support the development and staged implementation of reforms to the NEM wholesale market that support the achievement of the National Electricity Objectives including affordability, reliability and emission reduction in the long-term interests of consumers and prosperity of Australia's economy.

11. The expert panel should consider:

   - Interactions with the NEM reliability framework, to ensure clear and transparent settings that align with the proposed reforms and best serve the long-term interest of consumers.
   - Interactions with governments' renewable energy targets and policies in promoting investment, including the role of enduring jurisdictional schemes such as the NSW Roadmap.
   - The importance of decarbonising Australia's electricity system for achieving the Australian Government's legislated commitments to achieving a 43 per cent reduction in emissions on 2005 levels by 2030 and net zero emissions by 2050.
   - The pathway for implementation of the reforms, including the requirement for agreement at ECMC before amendments to the National Electricity Law (NEL) and National Electricity Rules (NER) can be progressed.

12. The expert panel will not consider options that involve implementation of carbon trading schemes, carbon markets or that entail governments supporting new fossil fuel generation.

13. In forming its recommendations, the expert panel will consider the work of the former Energy Security Board on incentivizing firmed dispatchable generation and storage capacity in the NEM, as well as AEMO's Integrated System Plan as the most comprehensively outlined pathway for the NEM through the energy transformation.

14. The expert panel will prepare a roadmap detailing the timelines and responsible parties for implementation of the review's recommendations.

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Process

15. The expert panel will undertake an appropriate public consultation process including holding public forums, inviting submissions, and releasing a report with draft recommendations to the public before making its final recommendations.

16. The expert panel will consult with state and territory governments. The review will also consult with the Australian Energy Market Commission, the Australian Energy Market Operator, the Australian Energy Regulator, the Australian Competition and Consumer Commission, the Clean Energy Regulator and Clean Energy Finance Corporation, industry participants, unions, and consumer representatives on relevant matters.

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Appendix B – Stakeholder engagement

Stakeholder engagement – first phase (January – July)

The first phase of the Review was shaped by the Panel's intention to establish an open and constructive consultation process. Given the breadth of issues facing the NEM, the Panel sought to hear from as wide a range of perspectives as possible, including governments, market bodies, generators, retailers, investors and electricity consumers of all sizes. Engagement also extended internationally to learn from experiences in other jurisdictions. A mix of bilateral and multilateral forums enabled stakeholders to express their views and, importantly, to hear the views of others.

Initial consultation

Engagement began with a public consultation on the scope of the Review, inviting submissions between 11 December 2024 and 14 February 2025. A short paper outlined the Panel's early thinking and welcomed feedback on issues identified in the Terms of Reference. During this period, the Panel made itself available to meet with stakeholders who wished to discuss the Review or provide additional context beyond written submissions.

Collaboration and data sharing

The Panel organised several small forums to understand in detail the finer aspects of wholesale market operation. The Panel was also fortunate to receive detailed information and data sets from industry participants, including information that was provided commercial-in-confidence. The Panel is appreciative to industry for being so willing to engage and share critical information that shaped the Panel's thinking.

Open forums

Between 13 May and 3 June 2025, the Panel convened a series of open forums, both online and in each NEM jurisdiction. These sessions summarised emerging themes from initial consultation and shared the Panel's early direction for discussion. Each forum included time for questions and comments, and the Panel also posed questions to help explore issues raised by participants. These forums provided an opportunity for stakeholders to test ideas and identify areas that required further work.

Industry expert engagement

The Panel also held several "lunch and learn" sessions with academics, senior officials and industry specialists to deepen its understanding of complex market and system issues. In addition, the Panel undertook international engagements. These included meetings in New Zealand, the United Kingdom and the United States, and participation in International Energy Agency forums to better understand the challenges and reforms underway in comparable systems. These discussions informed the Panel's analysis.

Stakeholder engagement – second phase (August – December 2025)

Following release of the Draft Report on 6 August 2025, the second phase of engagement focused on refining the recommendations and considering the practical steps required for implementation. Feedback during this phase was important in strengthening the final report.

A range of engagement channels were used, including:

- **Public submissions** on the Draft Report (over 120 stakeholder submissions)
- An open online forum organised by The Energy attended by a very large number of interested parties
- **Three additional open online forums** on the short-, medium- and long-term aspects of the Panel's recommendations, attended by more than 250 stakeholders
- **Co-design workshops and advisory-group forums** to test options and clarify design questions
- **Targeted policy discussion papers** seeking comment on specific design principles
- **Ongoing engagement with governments**
- **Individual meetings** with stakeholders to understand detailed operational considerations
- **Weekly meetings with market bodies** to draw on their technical expertise

The Panel benefited from hearing from a range of individuals and organisations representing a wide cross-section of the energy industry. Formal written submissions on the Draft Report can be accessed online at the *Have Your Say* website.

Targeted industry consultation

The Panel also convened a series of workshops and recurring meetings with industry leaders to gather insights relevant to the implementation roadmap. These sessions offered a practical perspective on sequencing, governance and readiness considerations, and helped the Panel understand the implications of different approaches.

Table 7 – Detailed design consultation

Meeting name	Purpose	Frequency	Participants
Contracts Co-Design workshops	Industry-led design process to develop a set of derivative contracts that could be utilised for the purposes of the ESEM and MMO.	4 in person sessions	ASX Energy, SA Water, ANZ, Commonwealth Bank Australia (CBA), Macquarie Group, AGL Energy, Stanwell, Origin Energy, Iberdrola, Hydro Tasmania, Enel X, Akaysha Energy, Griffith University, Australian Financial Markets Australia (AFMA), Australian Energy Regulator (AER).
Market Making Obligation Policy Advisory Group online forum	To inform the Panel on key design considerations as it finalised the proposed framework and recommendations to ministers regarding the MMO.	2 forums	1st Energy , ACCC, AEMC, AEMO, AER, AFMA, AGL, Ai Group, Alinta Energy, ASX, Aurora Energy (Tas), Australian Energy Council, Clean Energy Council, CleanCo, CORE Markets, CS Energy, Energy Consumers Australia, Energy Locals, EnergyAustralia, ENGIE, EUAA, Genuity, GloBird, Hydro Tasmania, Iberdrola, Momentum Energy, Nexa Advisory, NSW Government, NZ EA, Origin Energy, Potentia Energy, Qld Treasury, SA DEM, Shell Energy/Powershop, Snowy Hydro/Red Energy, TAS DSG/ReCFIT, Tesla, TOD Markets, VivCourt Trading, Zen Energy.

Meeting name	Purpose	Frequency	Participants
Industry Peak Body Progress Group	Meeting with key industry associations and consumer representatives to seek insights and help shape the implementation plan for the proposed recommendations.	Weekly	Energy Council Australia (ECA), Australian Financial Markets Association (AFMA), AI Group, Energy Efficiency Council (EEC), Clean Energy Council (CEC), Clean Energy Investor Group (CEIG), Energy Networks Australia (ENA), Energy Users Association Australia (EUAA), St Vincent De Paul (SVDP).
Market Body Meetings	Meeting with the Market Bodies to seek insights and help shape the implementation plan for the proposed recommendations.	Weekly	AEMO, AEMC, AER, Aus Energy Services (ASL).

Acknowledgement and thanks

The Panel appreciates the significant time and effort invested by all stakeholders throughout the Review. Contributions, whether through submissions, meetings, workshops, forums or informal discussions, provided important insights and often prompted the Panel to revisit or refine its initial thinking. The Panel is grateful for the willingness of stakeholders to engage constructively, even on issues where views differed. This engagement has been valuable in strengthening the quality and practicality of the final recommendations.

The Panel has gratefully received formal written submissions from the following entities:

ACEN Renewables

ActewAGL

AGL

Akaysha Energy

Alan Pears

Alinta Energy

APA

ARENA

ASX

ATCO

Ausgrid

AusNet

Australian Aluminium Council

Australian Council of Trade Unions (ACTU)

Australian Energy Council (AEC)

Australian Energy Market Commission (AEMC)

Australian Energy Market Operator (AEMO)

Australian Energy Producers (AEP)

Australian Energy Regulator (AER)

Australian Financial Markets Association (AFMA)

Australian Geothermal Association

Australian Industry Greenhouse Network (AIGN)

Australian Pipelines and Gas Association (APGA)

Australian Solar Thermal Energy Association

Australian Workers Union (AWU)

BCA

BlueScope

Cau Thai

Centre for Policy Development

Changing Weather

Clean Energy Council (CEC)

Clean Energy Finance Corporation (CEFC)

Clean Energy Investor Group (CEIG)

CleanCo

Climateworks Centre

Community Power Agency

CS Energy

DAME Technologies

David Lee

Delta Electricity

EDF Power Solutions Australia

EEX AG

Eku Energy

Electric Vehicle Council (EVC)

Electrical Trades Union (ETU)

EMX Energy

Enel X Australia Pty Ltd

Energy and Water Ombudsman (NSW, QLD, SA)

Energy Consumers Australia (ECA)

Energy Efficiency Council (EEC)

Energy Networks Australia (ENA)

Energy Users Association of Australia (EUAA)

EnergyAustralia

ENGIE Australia & New Zealand

enX

Ergon Energy and Energex

Essential Energy

First Nations Clean Energy Network

FlowPower

Fluence

Future Fuels CRC Ltd.

Gas Energy Australia

Green Energy Trading

Helen Haines MP

Howard Lovatt

Hydro Tasmania

Iberdrola

Incite Energy

Institute for Energy Economics and Financial Analysis (IEEFA)

Investor Group on Climate Change

James Scott Chalmers

John Quiggan

Justice and Equity Centre

LDES Council

Lochard Energy

Maritime Union of Australia

Monash University

Nexa Advisory

Origin Energy

Paul Verschuer

Potentia Energy

Productivity Commission

R A Willoughby

Rainbow Power Company

RayGen

RE-Alliance

RWE

SA Power Networks

Sarea Coates

Satya Tanner

Save Our Surroundings Riverina

Sell and Parker

Shell

Smart Energy Council

Snowy Hydro

Solar Citizens

South Australian Council of Social Services

Stanwell

Squadron Energy

Sustainable Upper Ovens Inc

Tasmanian Government

Tesla

The Centre for Independent Studies

Tiho Ancev and Songze Qu

Tilt Renewables

Transgrid

Wonhas and Coles

Woodside Energy

Glossary

ACCC
Australian Competition and Consumer Commission

AEC
Australian Energy Council

AEMC
Australian Energy Market Commission

AEMC targets statement
list of the jurisdictional emissions reduction targets, prepared by the AEMC as required under the national energy laws, to be considered when applying the national energy objectives

AEMO
Australian Energy Market Operator

AER
Australian Energy Regulator

AFMA
Australian Financial Markets Association

APC
administered price cap

ARENA
Australian Renewable Energy Agency

ASX
Australian Securities Exchange

BESS
battery energy storage system

C&I user
commercial and industrial electricity user

CEFC
Clean Energy Finance Corporation

CEIG
Clean Energy Investor Group

CER
consumer energy resources

CFD
contract for difference

CFM
congestion relief market

CIS
Capacity Investment Scheme

Consumer
small electricity user (i.e. households and small businesses)

CPT
cumulative price threshold

CRM
congestion relief market

Customer
electricity user purchasing electricity from a retailer (distinct from ‘market customer’ – see below)

DCCEEW
Department of Climate Change, Energy, Environment and Water (federal)

DER
distributed energy resources

DMO
default market offer

DNSP
distribution network service provider

DOE
dynamic operating envelopes

DR
demand response

Dunkelflaute
periods of low wind and solar output

ECMC
Energy and Climate Change Ministerial Council

Electricity user
small and large-scale entities purchasing electricity either through a retailer or on the wholesale market

ESC
(Victorian) Essential Services Commission

ESEM
Electricity Services Entry Mechanism

ESS
essential system services

ESOO
electricity statement of opportunities

EV
electric vehicle

FCAS
frequency control ancillary services

FERM
Firm Energy Reliability Mechanism

FTR
financial transmission rights

GJ
gigajoule

IEEFA
Institute for Energy Economics and Financial Analysis

IPRR
integrating price responsive resources

IRM
interim reliability measure

ISP
Integrated System Plan (AEMO)

kW
kilowatt

LMP
locational marginal pricing

LRET
large-scale renewable energy target

LTESA
Long-Term Energy Service Agreement

Market customer
registered participant in the wholesale electricity market who purchases electricity for their own consumption or for on-sale to electricity users (i.e. retailers or C&I users)

MCL
maximum credit limit

MIC
market impact component

MLF
marginal loss factor

MLO
market liquidity obligation

MMO
market making obligation

MPC
market price cap

MPF
market price floor

MT PASA
medium-term projected assessment of system adequacy

MW
megawatt

MWh
megawatt-hour

NCC
network capability component

NEL
National Electricity Law

NEM
National Electricity Market

NEMDE
NEM Dispatch Engine

NEO
National Electricity Objective

NER
National Electricity Rules

NERL
National Electricity Retail Law

NERR
National Electricity Retail Rules

NSCAS
network support and control ancillary services

Ofgem
Office of Gas and Electricity Markets (UK)

OTC
over-the-counter

PPA
power purchase agreement

PRR
price-responsive resources

PV
photovoltaic

REGO
renewable electricity guarantee of origin

RERT
reliability and emergency reserve trader

RET
renewable energy target

REZ
renewable energy zone

RIT-T
regulatory investment test for transmission

RRO
Retailer Reliability Obligation

SA FERM
South Australia Firm Energy Reliability Mechanism

SOC
state of charge

SRAS
system restart ancillary services

SRMC
short-run marginal costs

ST PASA
short-term projected assessment of system adequacy

TNSP
transmission network service provider

USE
unserved energy

VCR
value of customer reliability

VPP
virtual power plant

VRE
variable renewable energy

VSR
voluntarily scheduled resource

WDRM
wholesale demand response mechanism